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Varkey et al.

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(54) **METHODS AND CABLES FOR USE IN FRACTURING ZONES IN A WELL**

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(51) **Int. Cl.**
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(52) **U.S. Cl.**
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(58) **Field of Classification Search**
None
See application file for complete search history.

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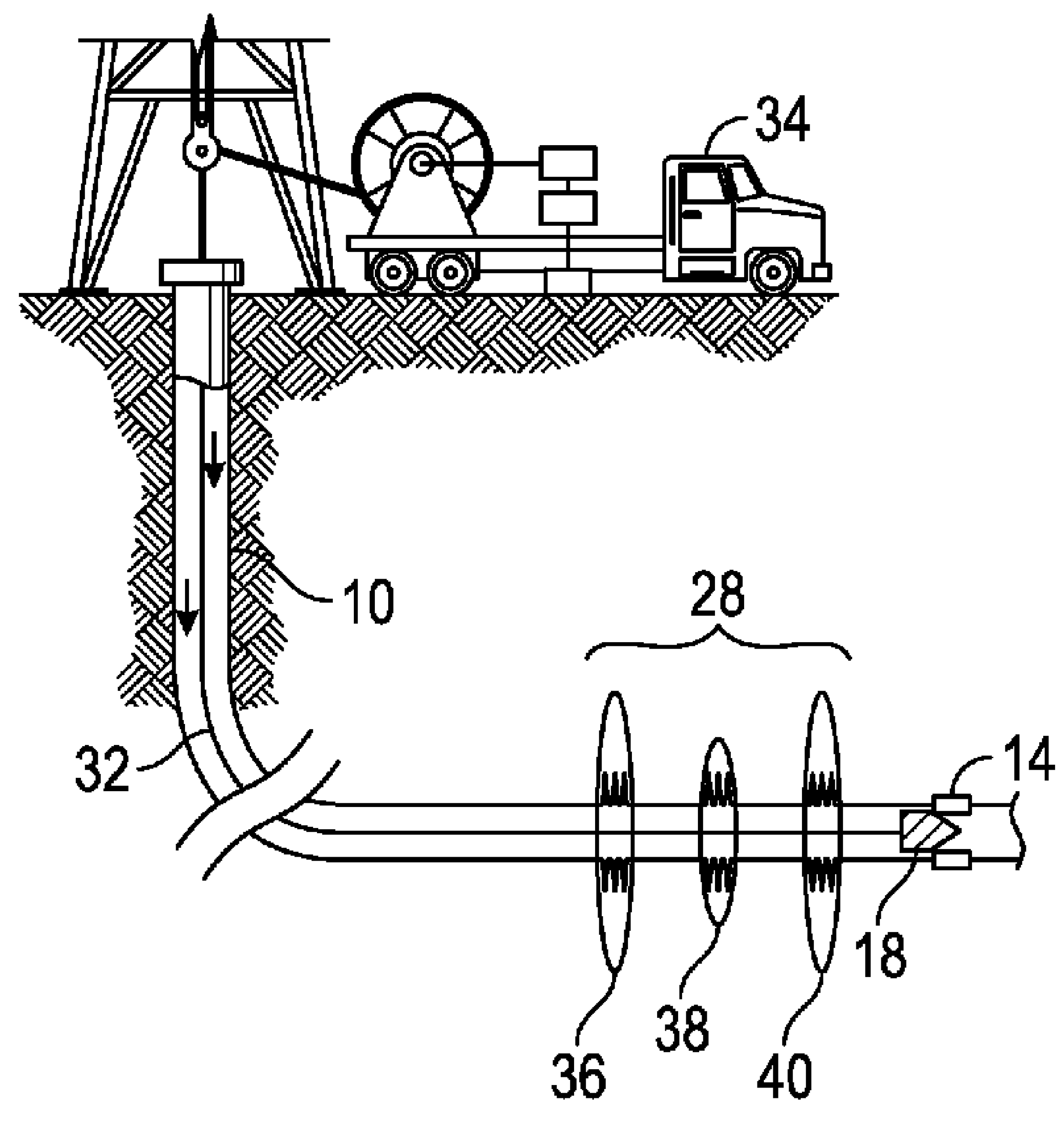
(57) **ABSTRACT**

Method and system for multi-stage well treatment wherein an isolating device is tethered with a distributed measurement cable during the treatment of one or more stages. The cable having a cable core including an optical fiber conductor.

29 Claims, 10 Drawing Sheets



Related U.S. Application Data

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(51) **Int. Cl.**

E21B 47/12	(2012.01)
E21B 23/01	(2006.01)
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E21B 43/116	(2006.01)
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E21B 43/14	(2006.01)
E21B 43/267	(2006.01)

(52) **U.S. Cl.**

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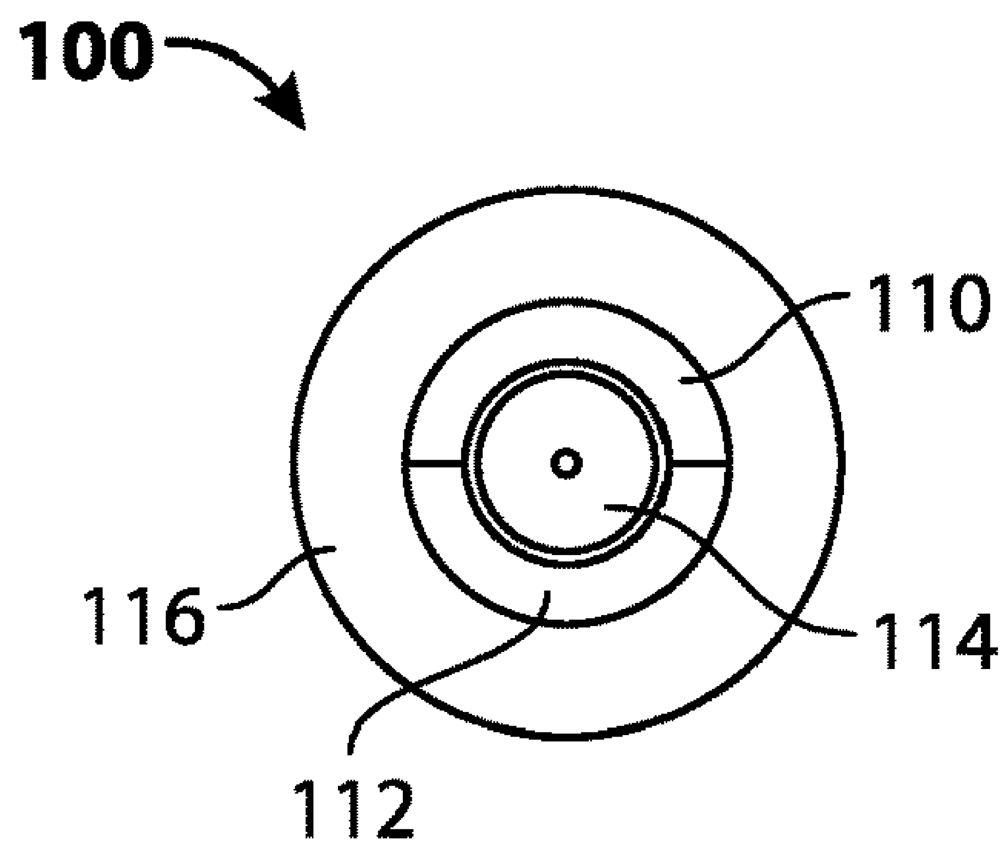


FIG. 1

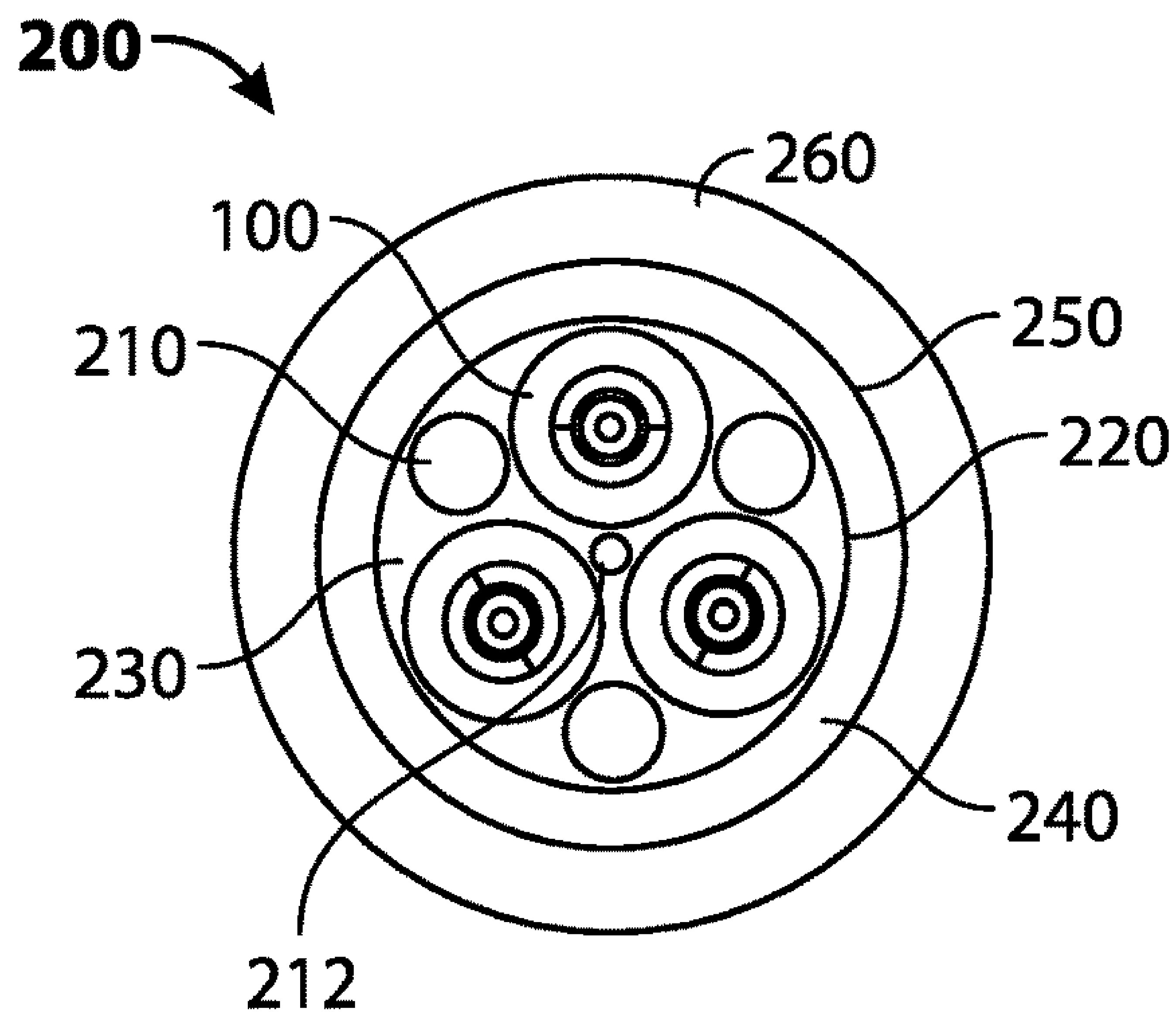
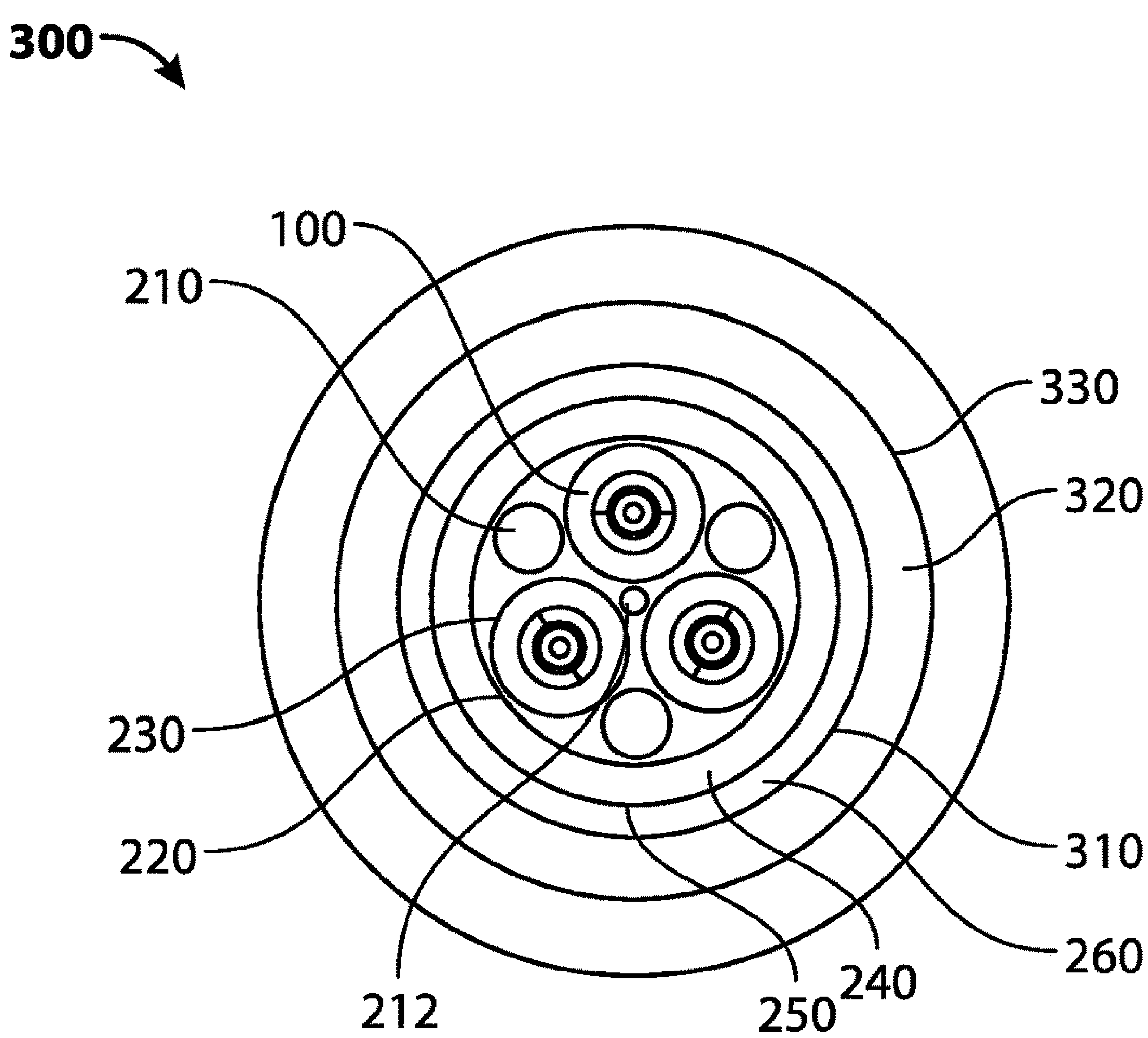


FIG. 2



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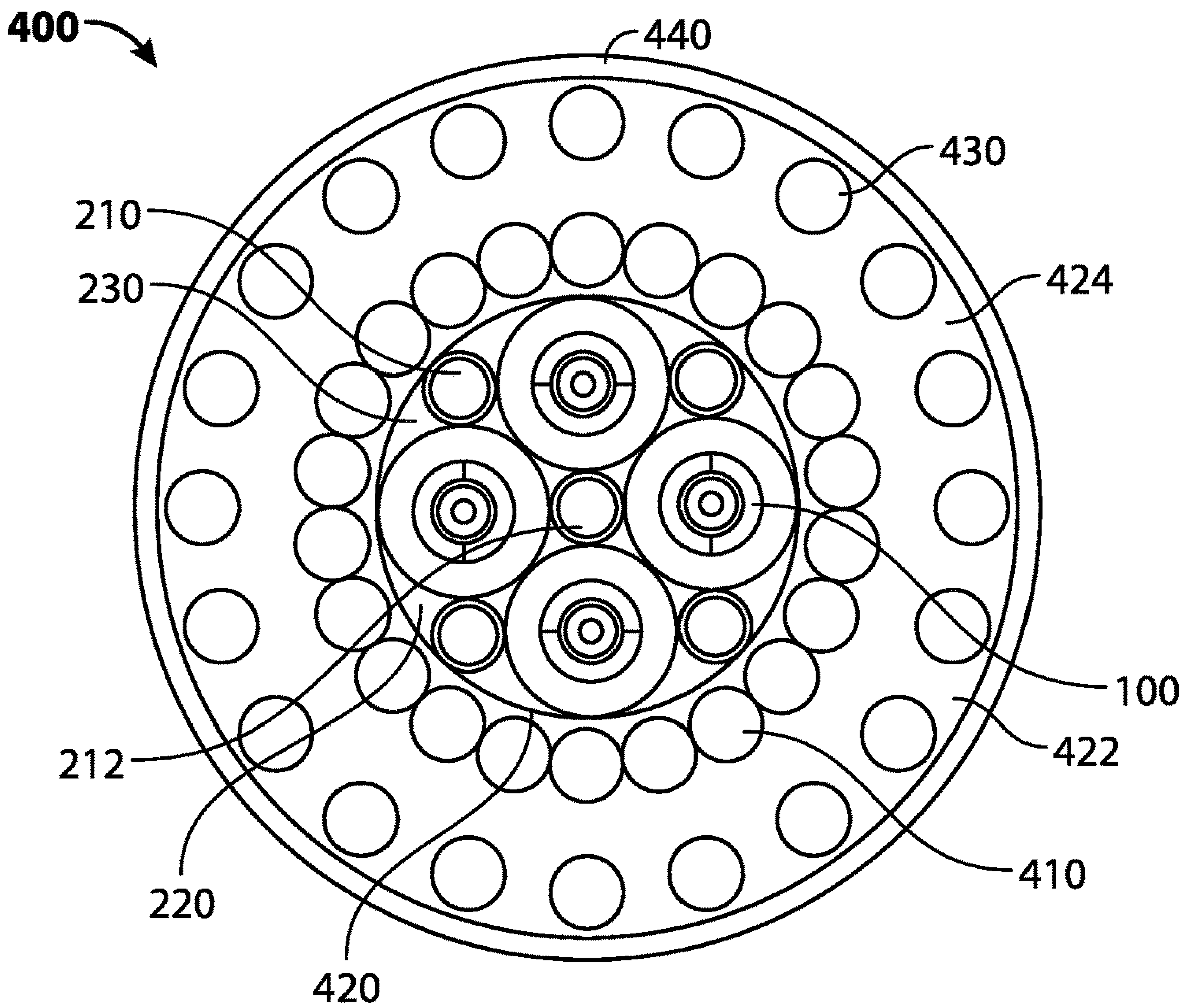
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FIG. 4

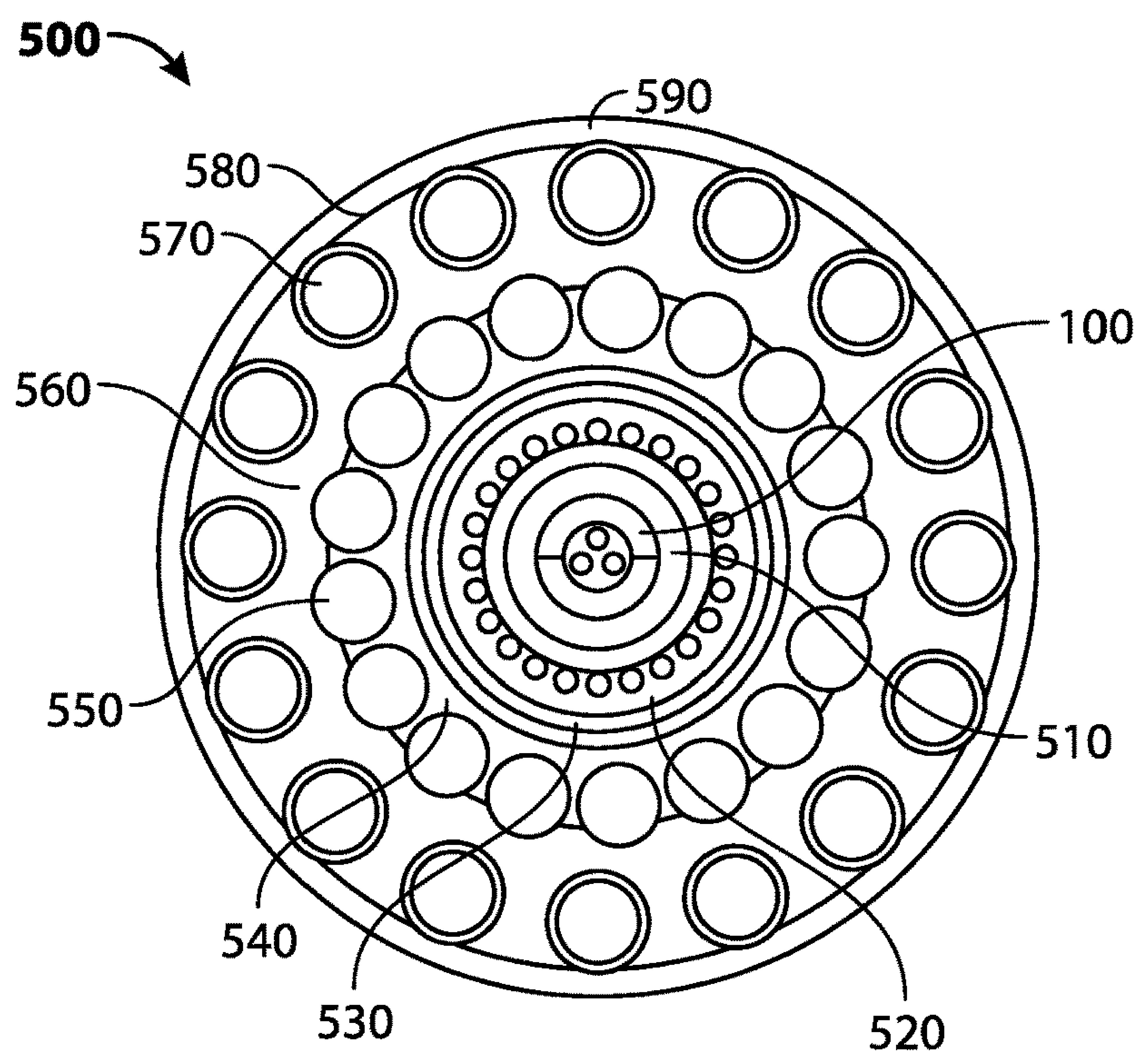
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FIG. 5

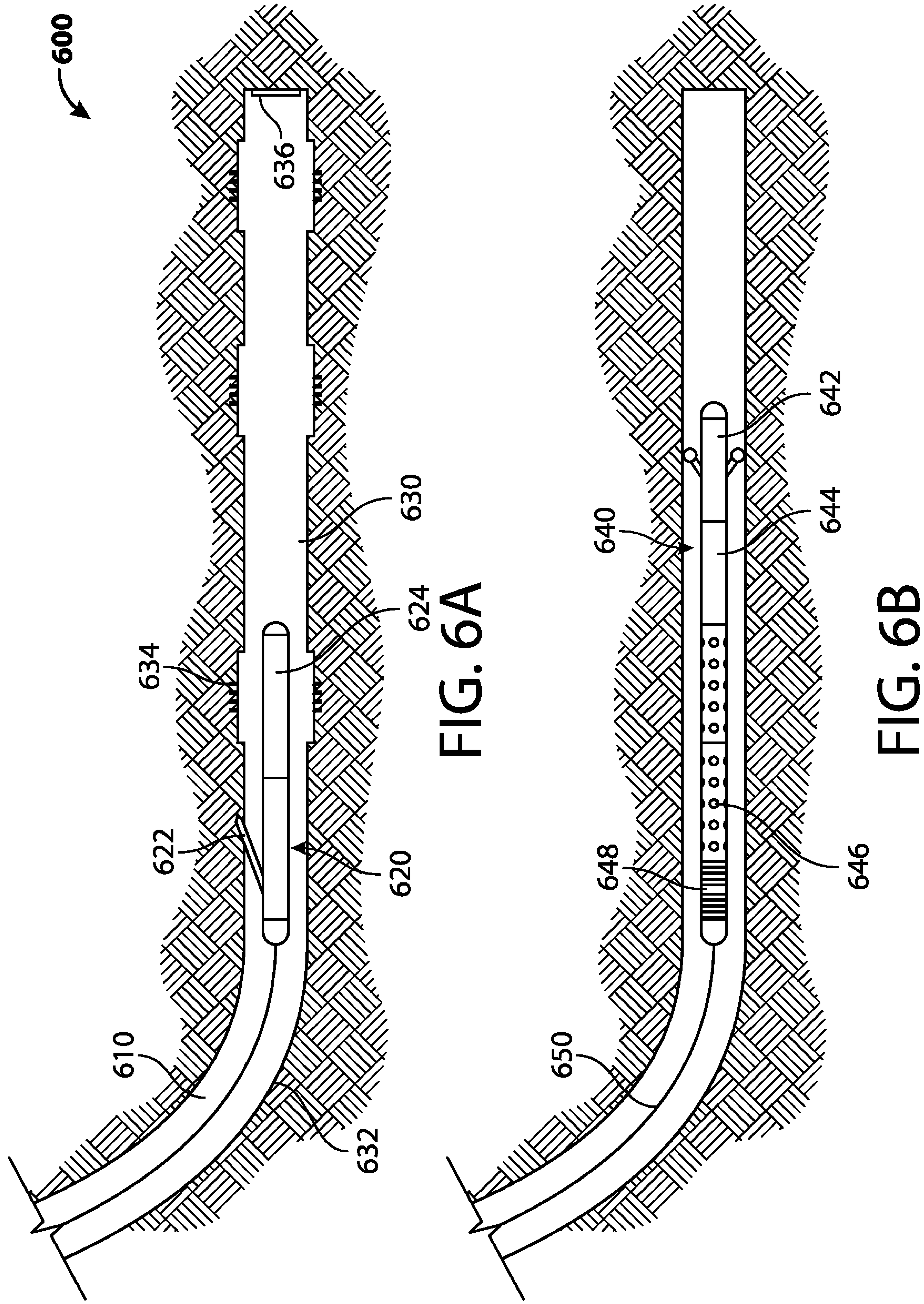

FIG. 6A

FIG. 6B

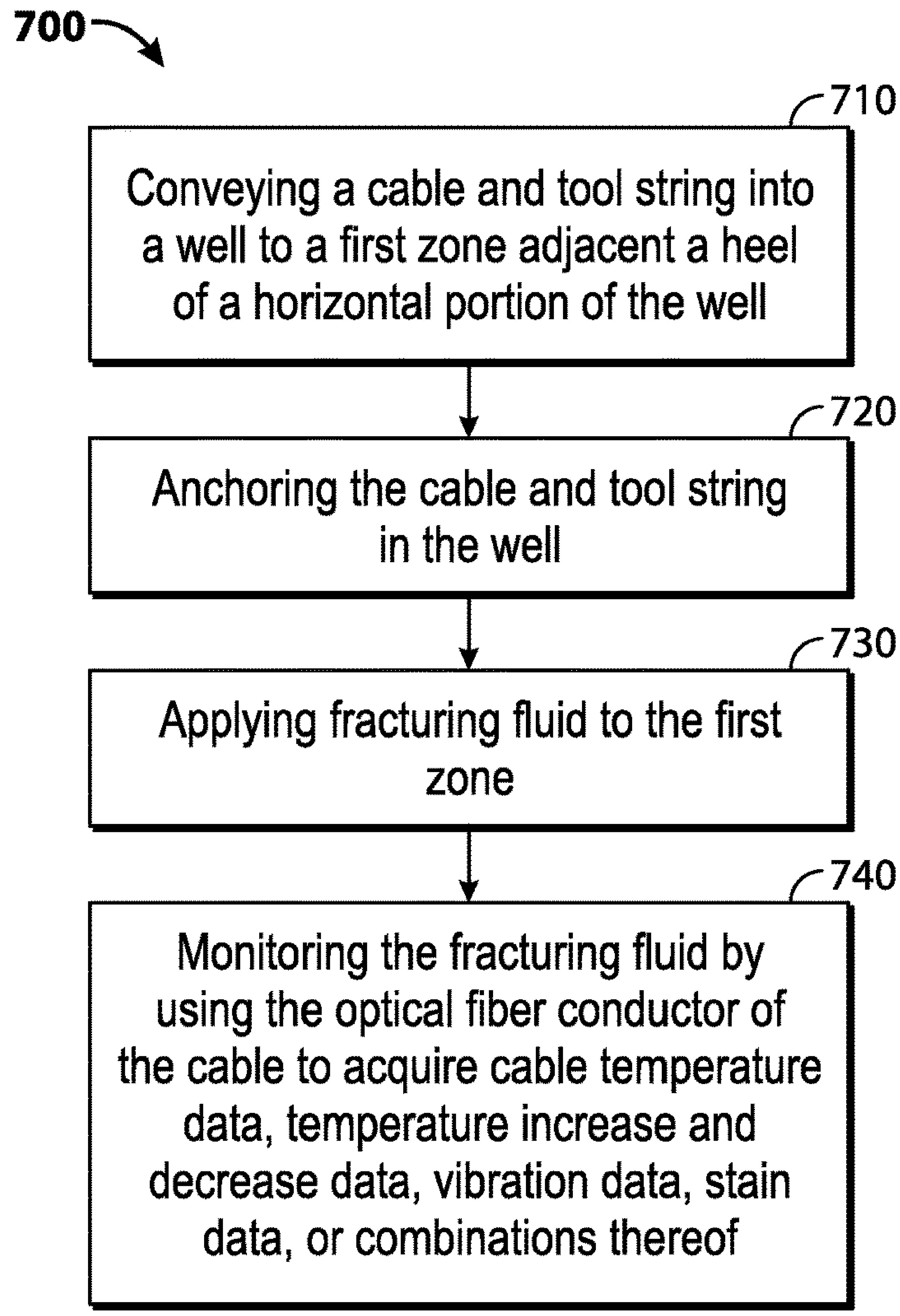
700
710
Conveying a cable and tool string into a well to a first zone adjacent a heel of a horizontal portion of the well
720
Anchoring the cable and tool string in the well
730
Applying fracturing fluid to the first zone
740
Monitoring the fracturing fluid by using the optical fiber conductor of the cable to acquire cable temperature data, temperature increase and decrease data, vibration data, stain data, or combinations thereof

FIG. 7

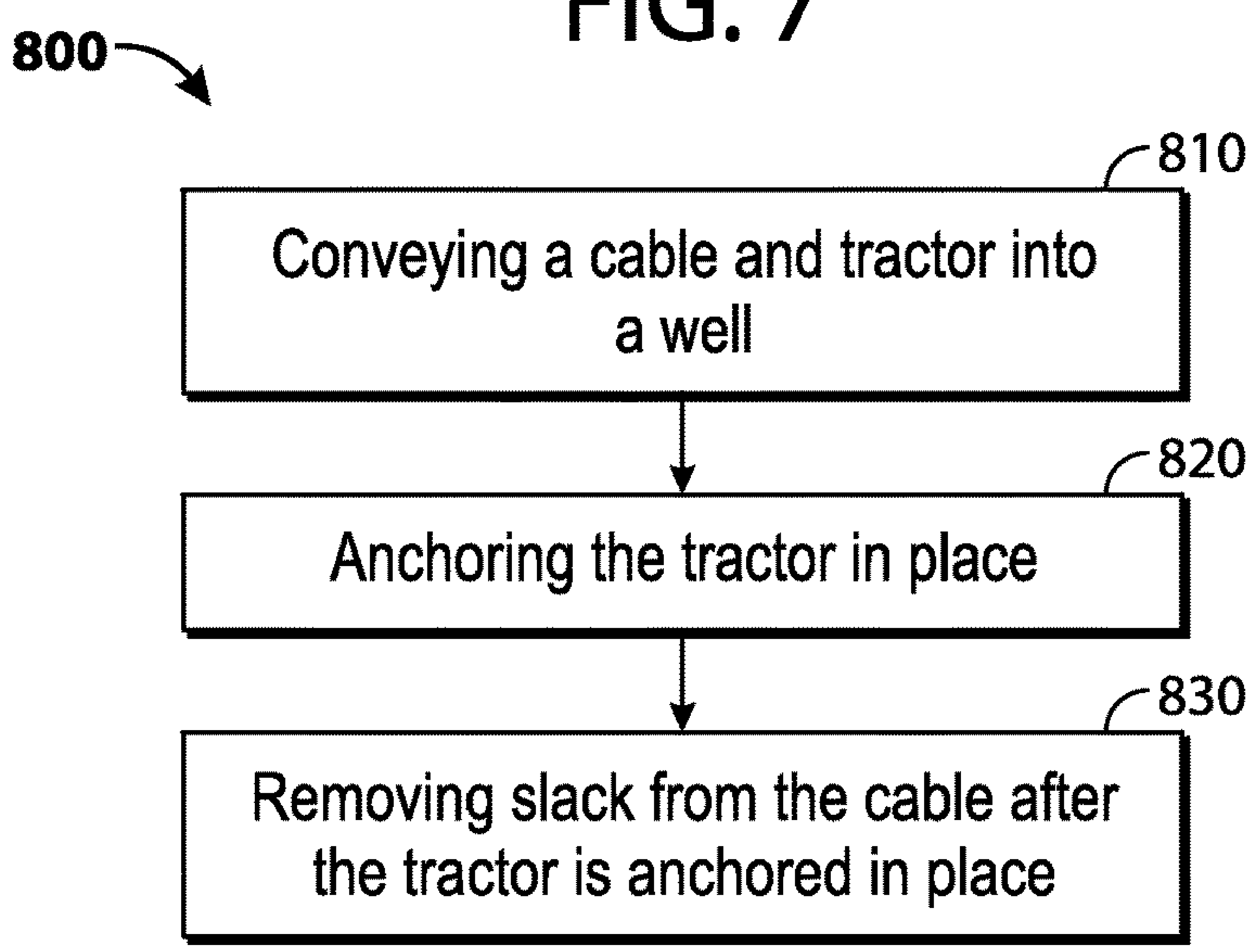
800
810
Conveying a cable and tractor into a well
820
Anchoring the tractor in place
830
Removing slack from the cable after the tractor is anchored in place

FIG. 8

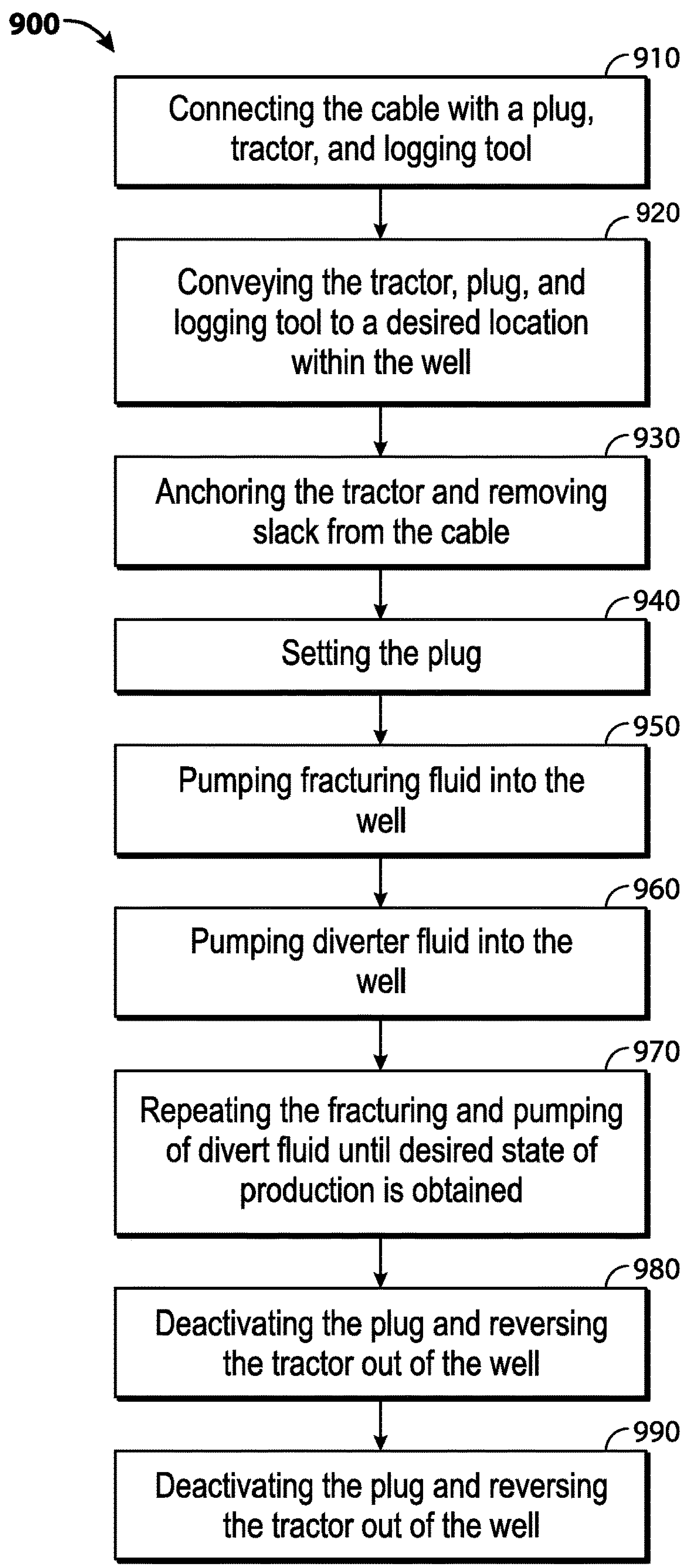
900
910
Connecting the cable with a plug, tractor, and logging tool
920
Conveying the tractor, plug, and logging tool to a desired location within the well
930
Anchoring the tractor and removing slack from the cable
940
Setting the plug
950
Pumping fracturing fluid into the well
960
Pumping diverter fluid into the well
970
Repeating the fracturing and pumping of divert fluid until desired state of production is obtained
980
Deactivating the plug and reversing the tractor out of the well
990
Deactivating the plug and reversing the tractor out of the well

FIG. 9

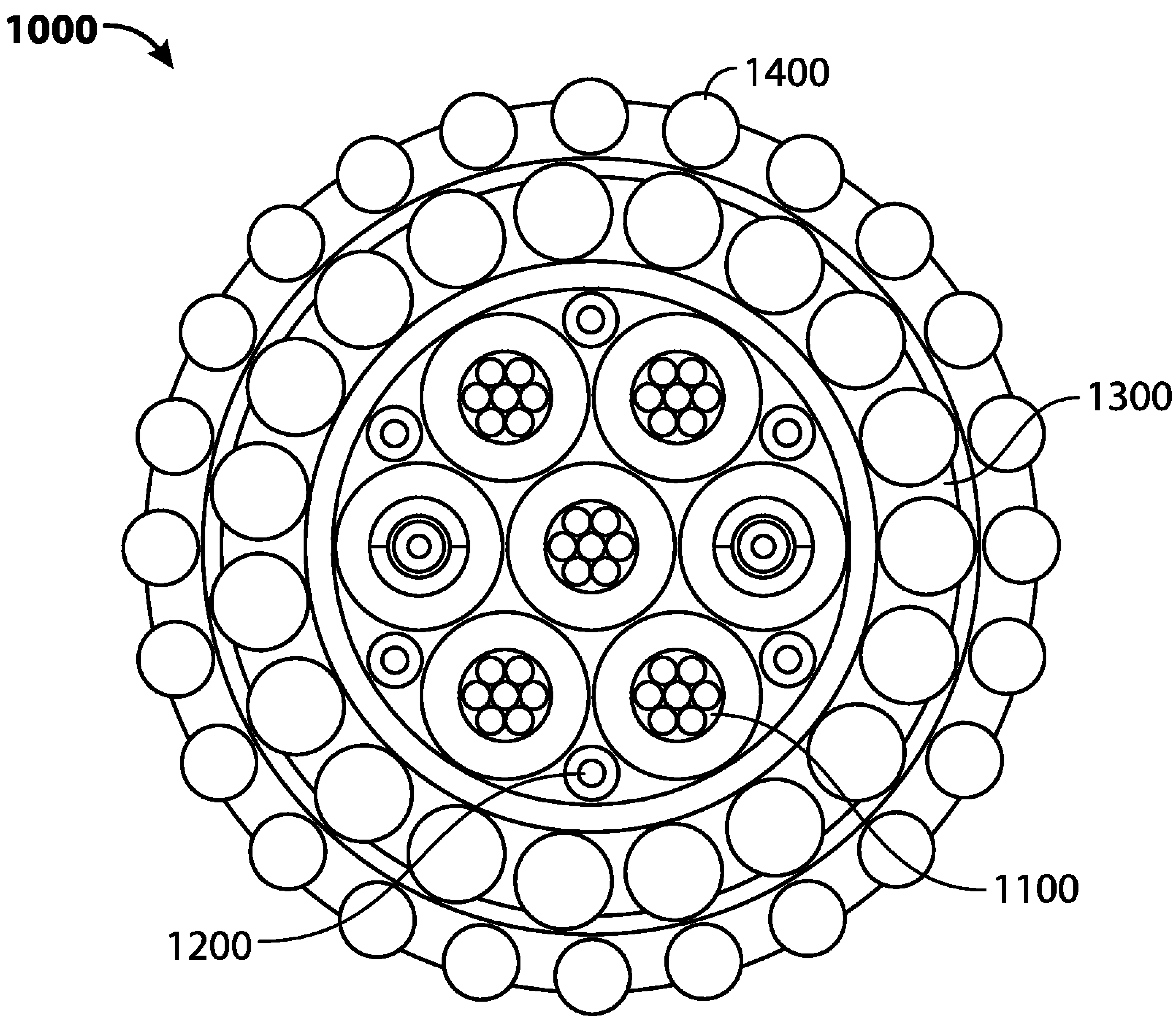

FIG. 10

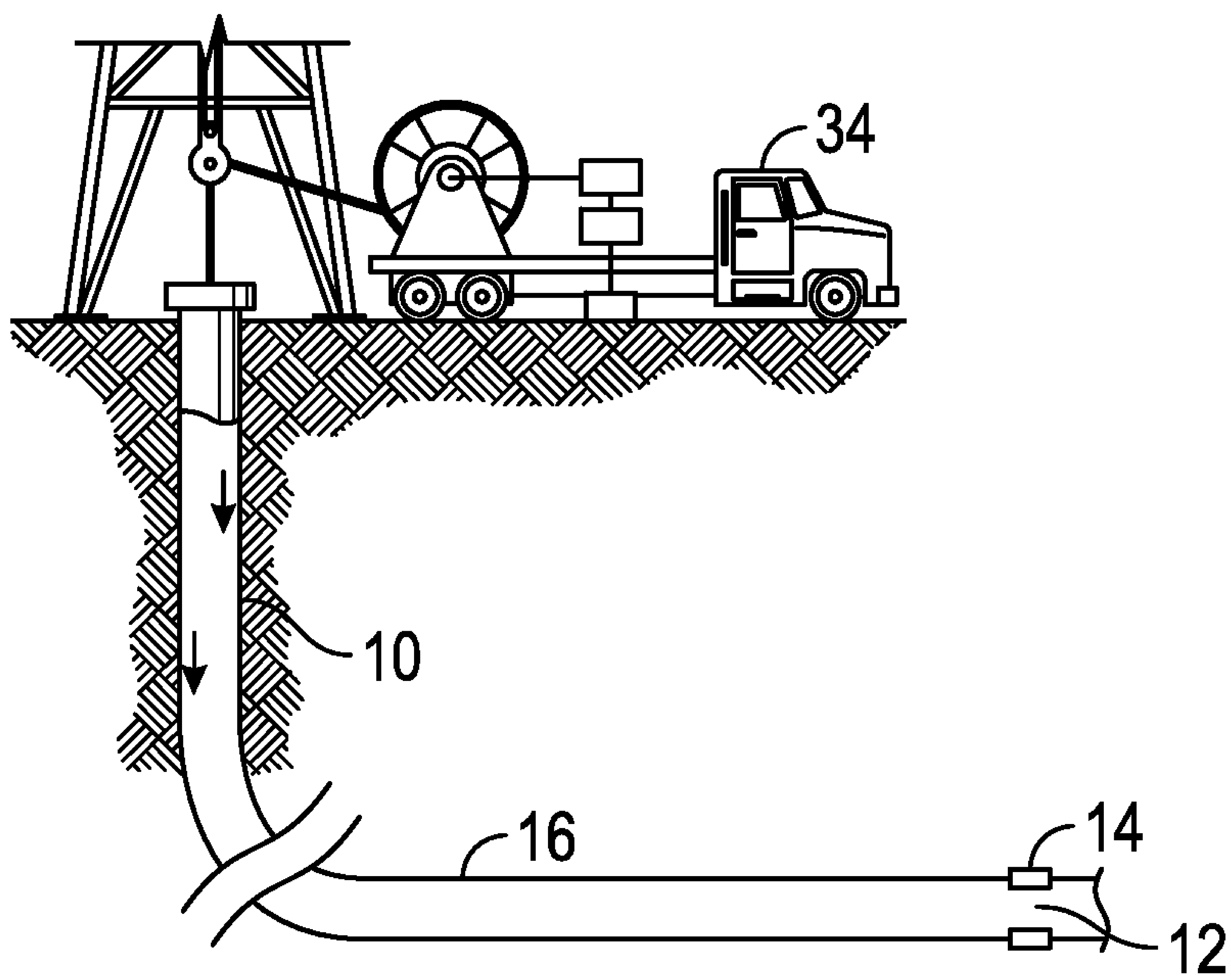

FIG. 11A

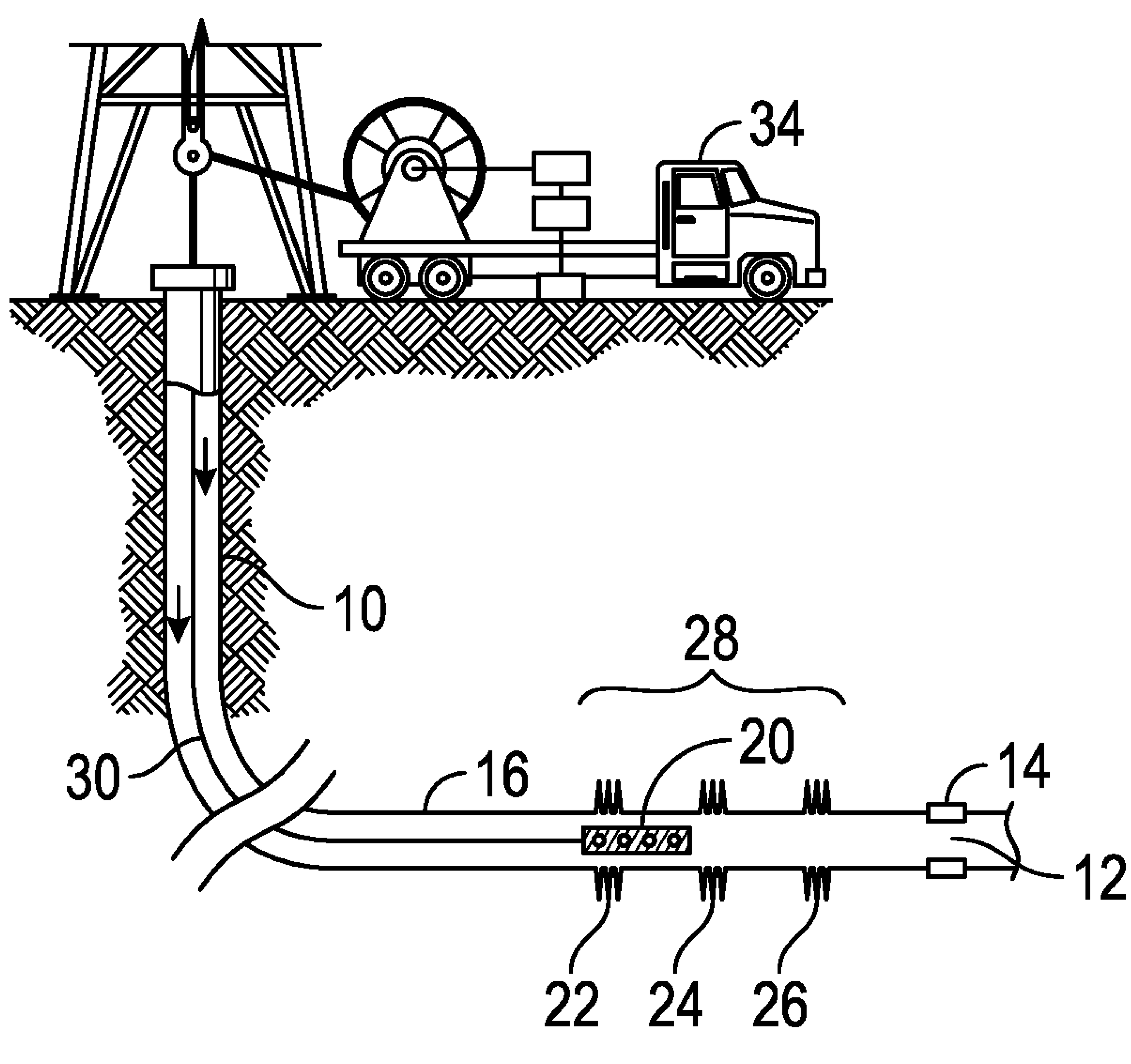

FIG. 11B

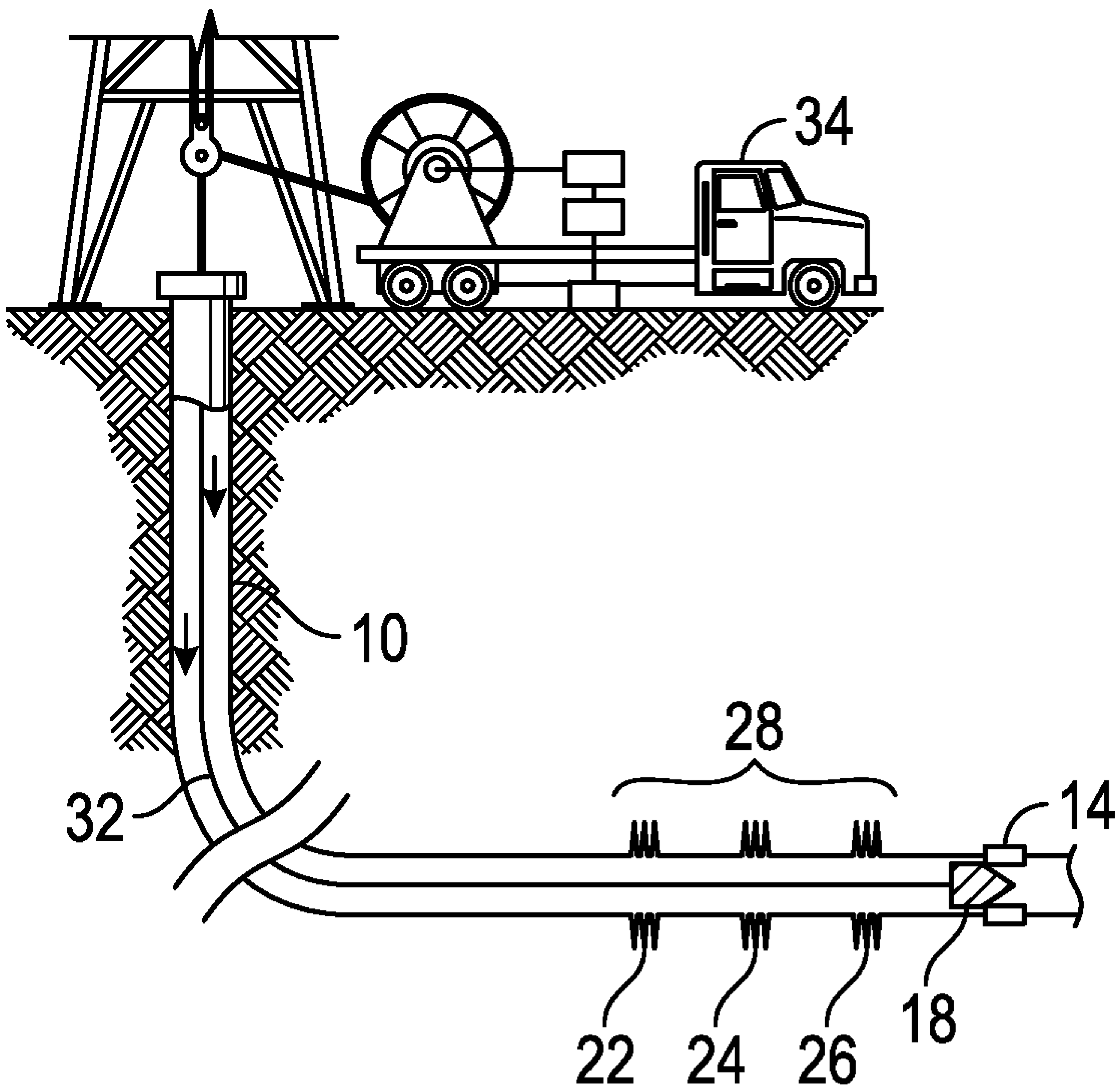

FIG. 11C

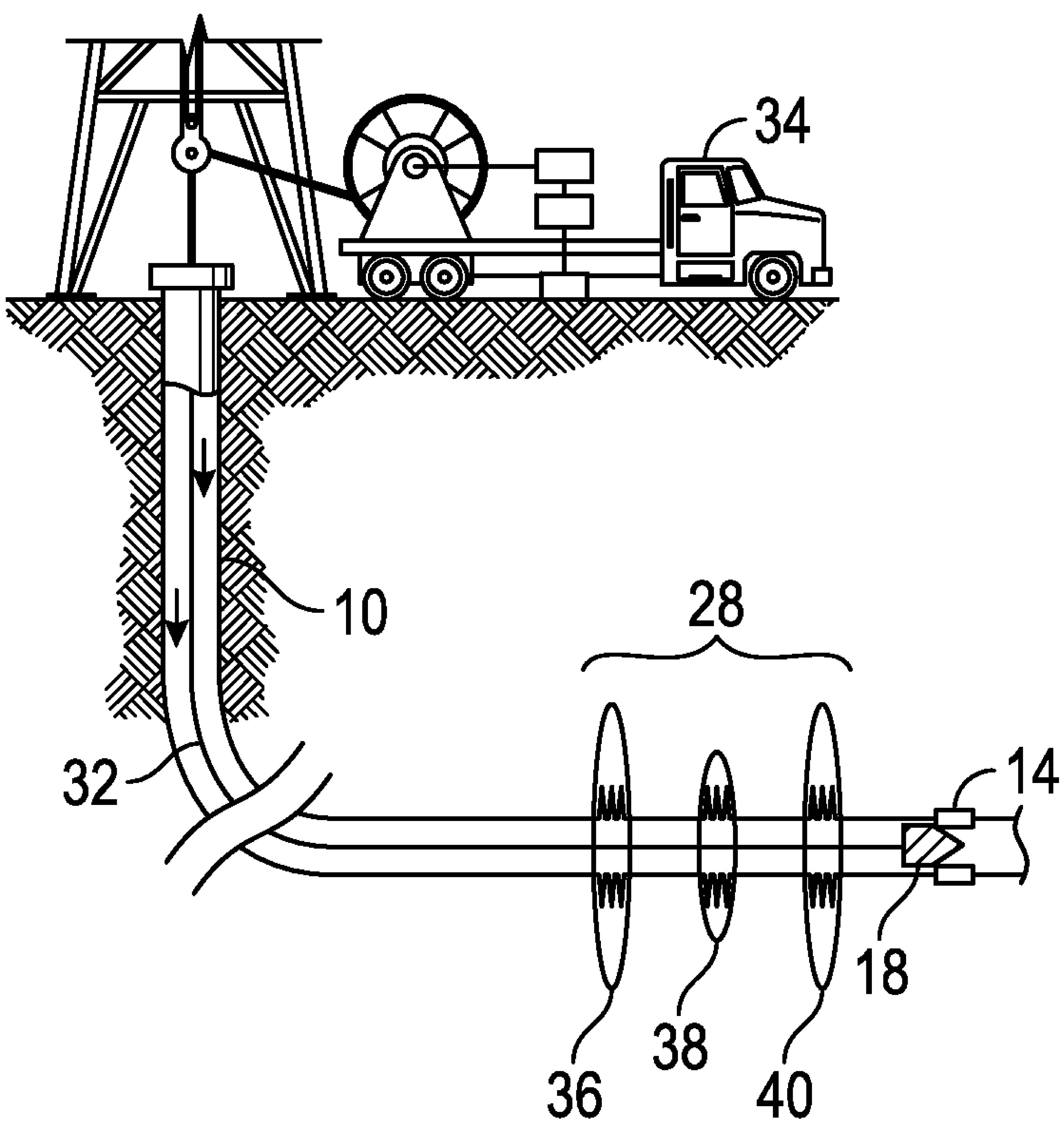

FIG. 11D

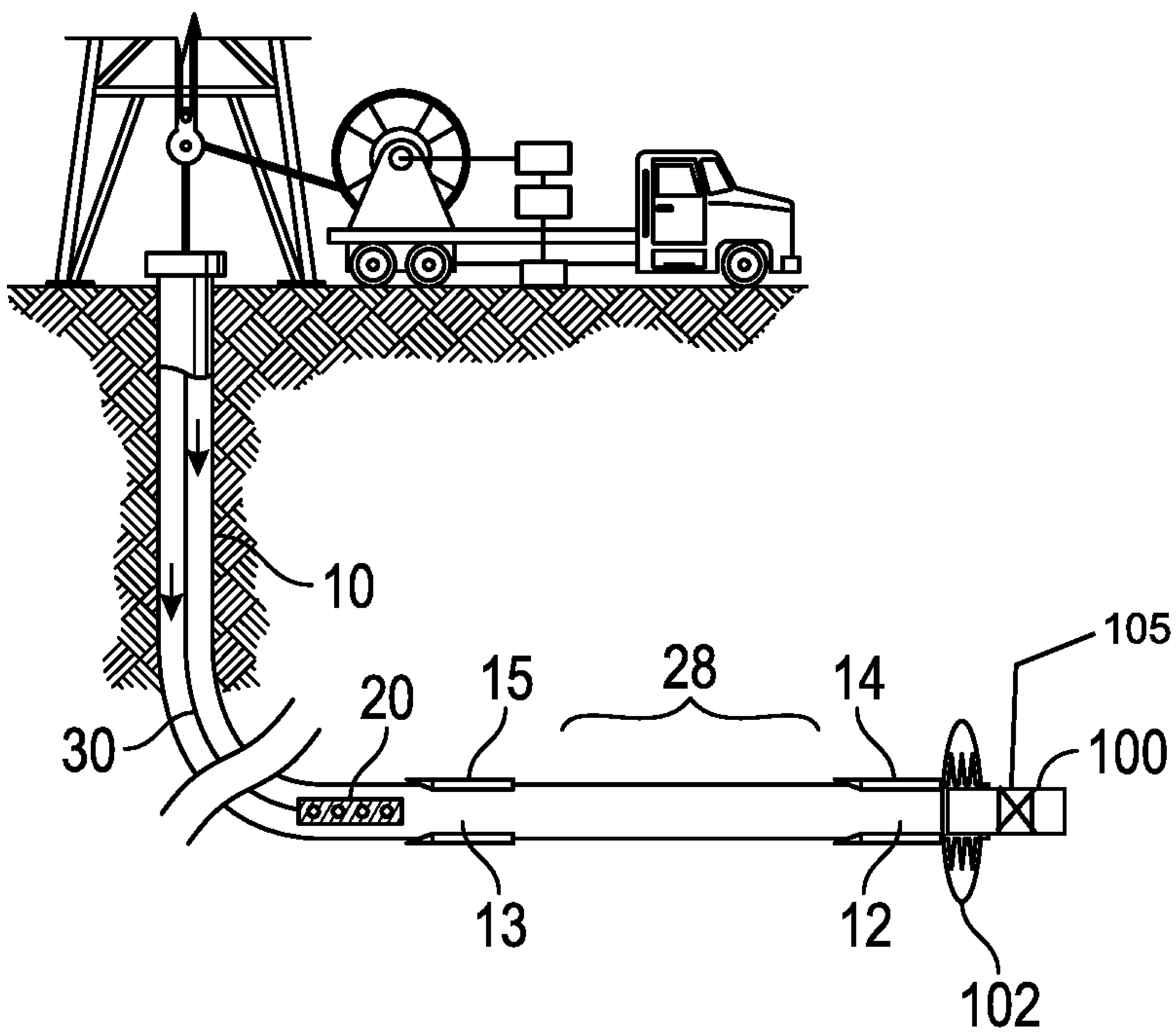

FIG. 12A

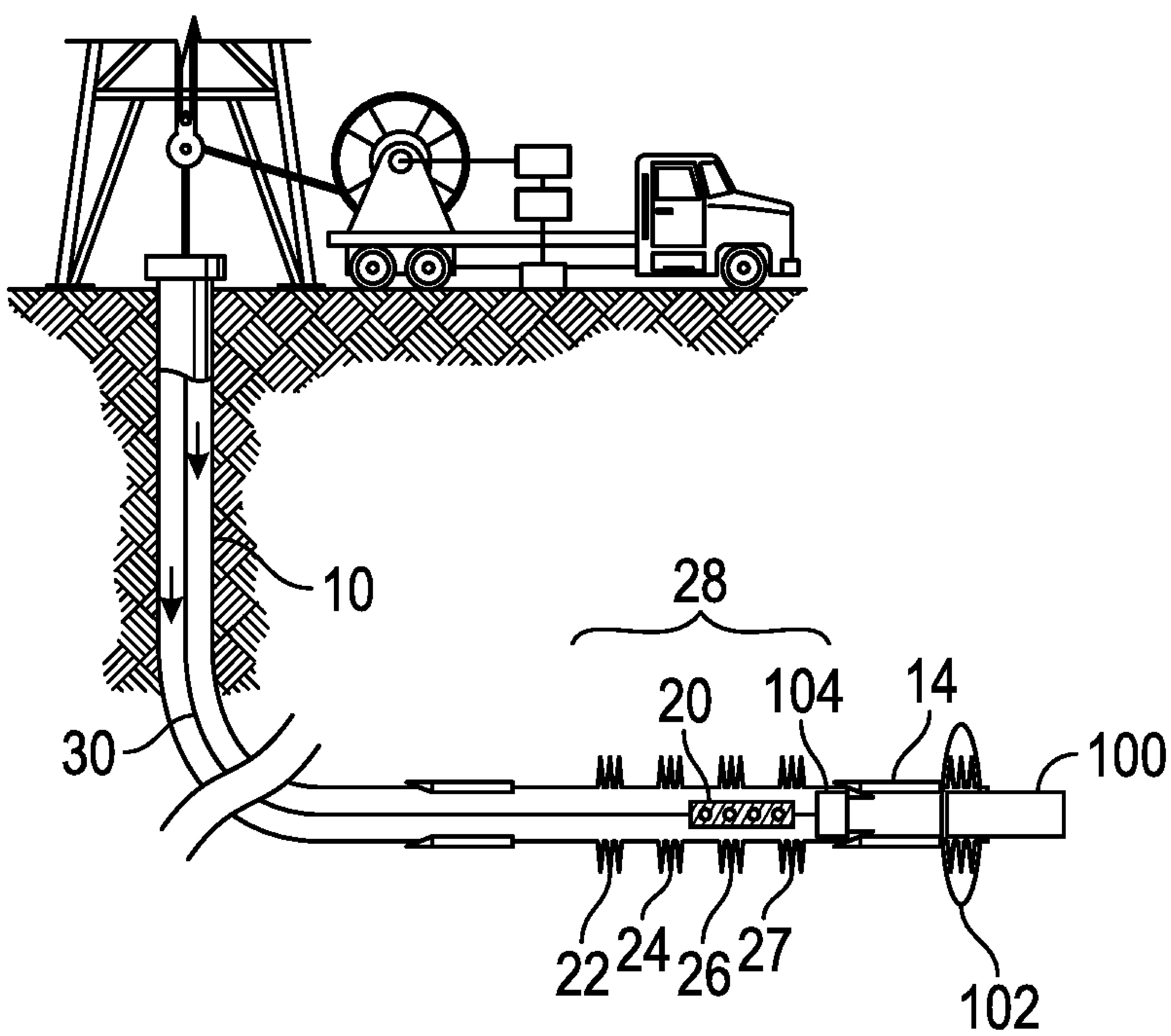

FIG. 12B

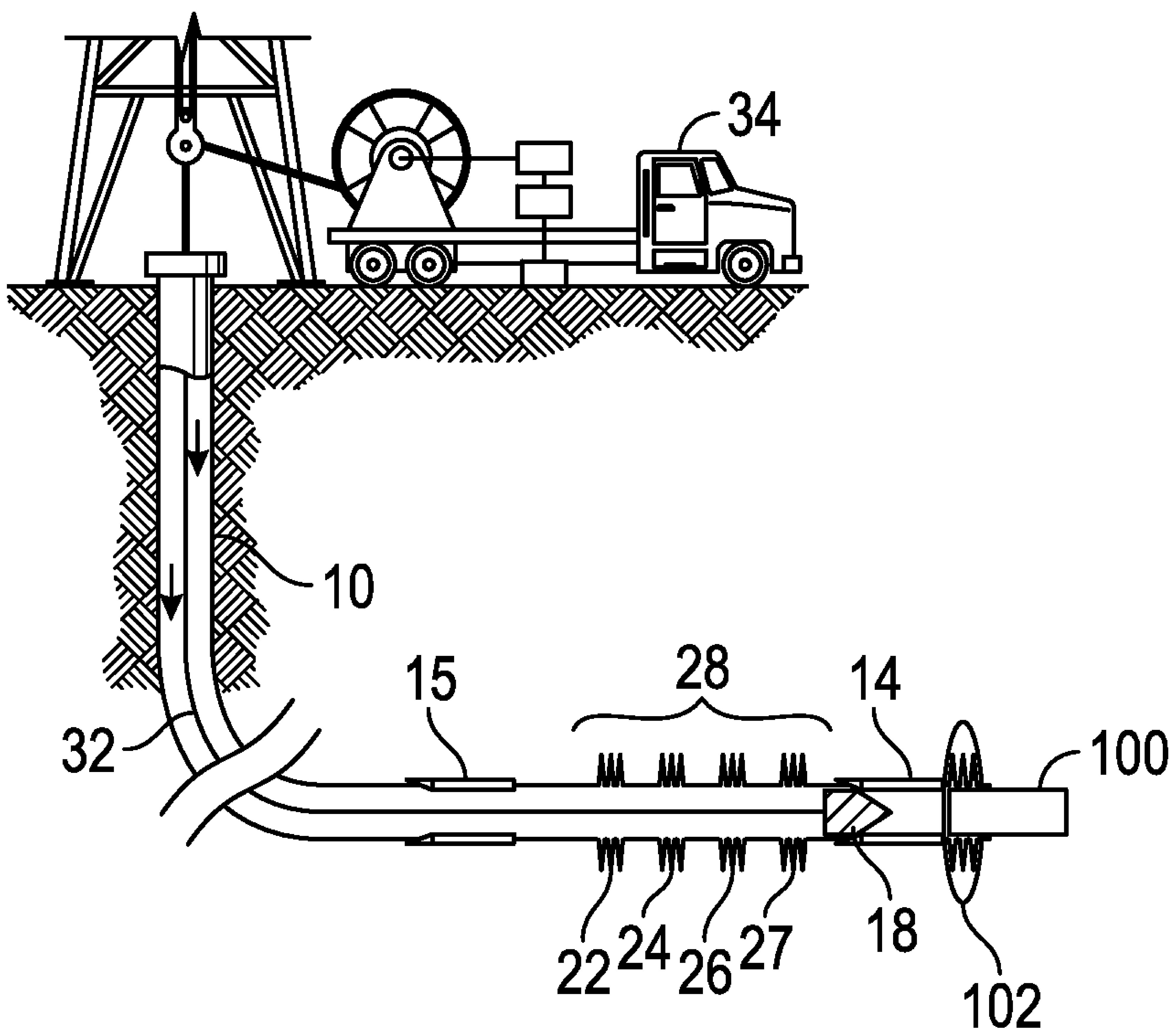

FIG. 12C

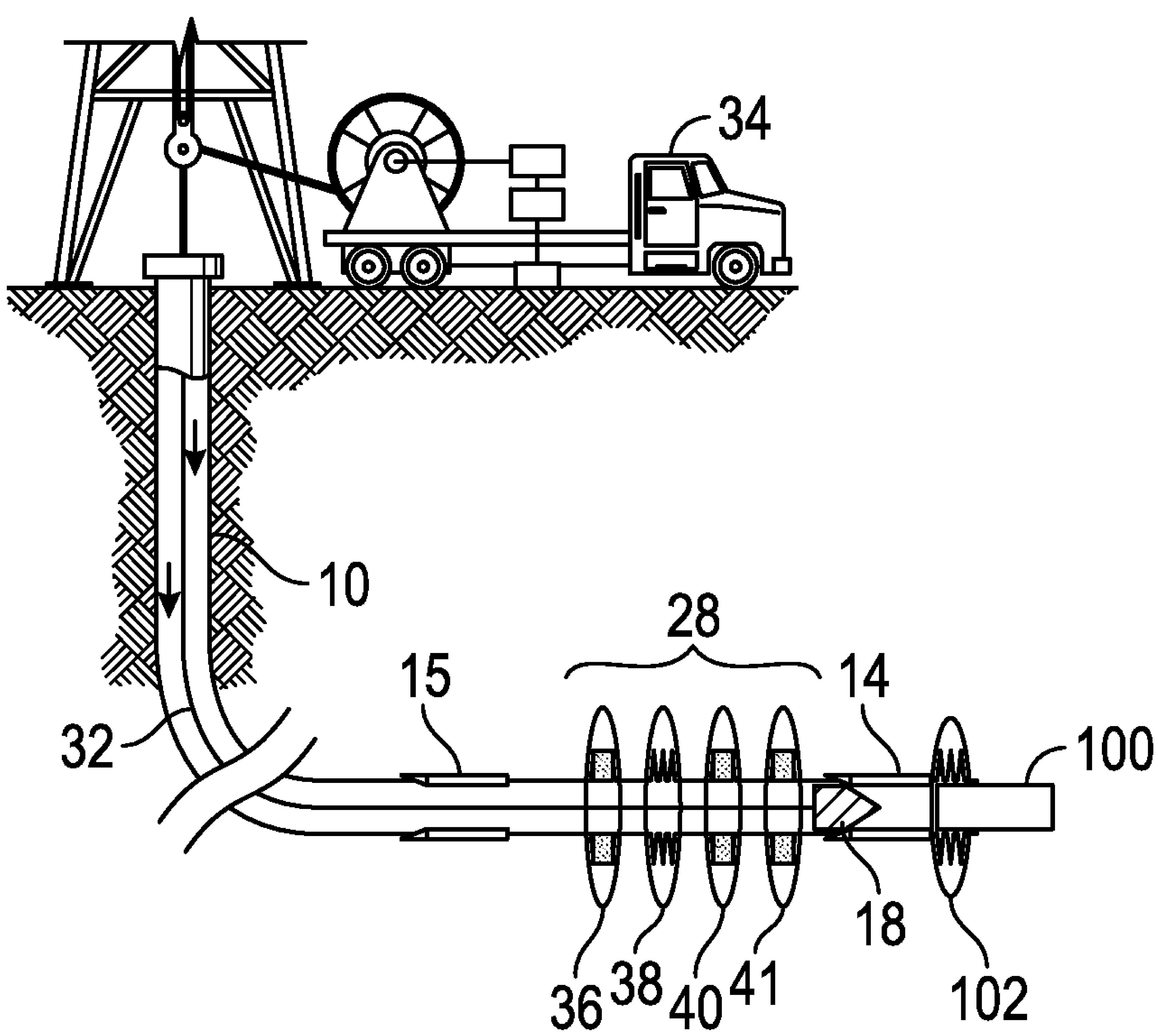

FIG. 12D

METHODS AND CABLES FOR USE IN FRACTURING ZONES IN A WELL

CROSS-REFERENCE TO RELATED APPLICATIONS

This application is a continuation in part of application U.S. Ser. No. 14/628,732 filed on Feb. 23, 2015 which claims priority and the benefit of U.S. Provisional Patent Application No. 62/027,696 that was filed on Jul. 22, 2014 and is entitled "Methods and Cables for Use in Fracturing Zones in a Well". U.S. Provisional Patent Application No. 62/027,696 and U.S. application Ser. No. 14/628,732 are both incorporated in their entirety herein by reference.

FIELD OF THE DISCLOSURE

The disclosure generally relates to methods and cables for use in fracturing zones in a well. The disclosure broadly relates to multistage fracturing operations.

BACKGROUND

Zones in a well are often fractured to increase production and/or allow production of hydrocarbon reservoirs adjacent a well. To ensure proper fracturing of zones it is useful to monitor the fracturing operations.

Efficient multi-stage well treatment such as fracturing can be a challenging operation that is often complicated by the difficulty of obtaining information about the progress of the treatment of the various stages, as well as the difficulty of properly locating and/or relocating various and different types of downhole tools, devices, objects, materials or other features for treatment of different stages within the same well and/or well interval. Frequently, it can be necessary with some types of multi-stage operations to retrieve downhole tools between stages, so that one stage or sub-stage of treatment can be completed and/or treatment of the next stage or sub-stage can begin, and or to lower a tool, device, object, material or other item from the surface. Each additional trip up or down the well adds time, cost and risk of improper treatment to the operation.

The industry is desirous of multi-stage treatment methods, systems and/or technology with improved efficiency and/or efficacy, e.g., that can effect multi-stage well treatment with better information gathering and/or fewer trips into and/or out of the well.

SUMMARY

Embodiments pertain to methods for multi-stage well treatment, comprising perforating a first interval in the well above a first target depth; deploying to the first target depth an isolation object tethered to a distributed measurement cable from the surface; isolating the well at the first target depth with the isolation object; treating the first perforated interval in a plurality of stages; and concurrently receiving measurements from the distributed measurement cable for monitoring each stage of the treatment.

An example cable for use in the methods includes a cable core. The cable core includes an optical fiber conductor. The optical fiber conductor includes a pair of half-shell conductors. An insulated optical fiber is located between the pair of half-shell conductors. The insulated optical fiber is coupled with the pair of half-shell conductors. The optical fiber conductor also includes an optical fiber conductor jacket disposed about the pair of half-shell conductors.

An example of a system for monitoring fracturing operations includes a cable. The cable comprises a cable core having an optical fiber conductor. The optical fiber conductor includes a pair of half-shell conductors. An insulated optical fiber is located between the pair of half-shell conductors. The insulated optical fiber is coupled with the pair of half-shell conductors, and an optical fiber conductor jacket is disposed about the pair of half-shell conductors. A tool string is connected with the cable, and the tool string has an anchor.

An example method of fracturing a well includes conveying a cable and tool string into a well to a first zone adjacent a heel of a horizontal portion of the well. The method also includes anchoring the cable and tool string in the well. The method also includes applying fracturing fluid to the first zone, and monitoring the fracturing by using the an optical fiber conductor of the cable to acquire cable temperature data, temperature increase and decrease data, vibration data, strain data, or combinations thereof.

The disclosure also relates to systems for multi-stage well treatment, comprising: a perforating system to convey a perforating device to perforate an interval in the well above a target depth; a deployment system to deploy an isolation object tethered to a distributed measurement cable from the surface to the target depth and isolate the well at the first target depth with the isolation object; a treatment system to treat the perforated interval with a treatment fluid in a plurality of stages; and a distributed measurement collection system to receive and interpret measurements from the distributed measurement cable during the treatment to monitor the plurality of the treatment stages.

Embodiments aim at methods for multi-stage well treatment, comprising installing in a casing string an initiation sub adjacent a toe of the well; installing in the casing string a plurality of retention subs at a first target depth and one or more successively higher target depths above the initiation sub; actuating the initiation sub to treat a stage adjacent the initiation sub; perforating a first interval in the well above the first target depth; deploying to the first target depth an isolation object tethered to a distributed measurement cable from the surface; seating the isolation object deployed in the retention sub installed at the first target depth to isolate the well at the first target depth; treating the first perforated interval in a plurality of stages; concurrently receiving measurements from the distributed measurement cable for monitoring each stage of the treatment; detaching the distributed measurement cable from the isolation object seated; and repeating at least the perforation, the deployment, the seating, the treatment, and the monitoring, one or more times with respect to successively higher intervals above the respective one or more successively higher target depths.

BRIEF DESCRIPTION OF THE DRAWINGS

FIG. **1** depicts a schematic of an optical fiber conductor.

FIG. **2** depicts a cable for use in fracturing operations according to one or more embodiments.

FIG. **3** depicts a schematic of another cable for use in fracturing operations according to one or more embodiments.

FIG. **4** depicts a schematic of a cable for use in fracturing operations according to one or more embodiments.

FIG. **5** depicts a schematic of a cable for use in fracturing operations according to one or more embodiments.

FIG. **6**A depicts an example system for monitoring fracturing operations according to one or more embodiments.

FIG. 6*b* depicts another example system for use in well to perform operations on the well.

FIG. **7** depicts an example method of fracturing zones in a well according to one or more embodiments.

FIG. **8** depicts an example method of placing a cable in well for monitoring.

FIG. **9** depicts an example method of placing a cable in a well for hydraulic fracturing and logging in a horizontal well.

FIG. **10** depicts an example cable with a hepta core for monitoring in a well.

FIG. **11**A schematically shows a well configuration according to a first operational sequence in a multi-stage treatment according to embodiments of the disclosure.

FIG. **11**B schematically shows a well configuration according to a second operational sequence in the multi-stage treatment of FIG. **11**A in accordance with embodiments of the present disclosure.

FIG. **11**C schematically shows a well configuration according to third operational sequence in the multi-stage treatment of FIGS. **11**A and **11**B in accordance with embodiments of the present disclosure.

FIG. **11**D schematically shows a well configuration according to a fourth operational sequence in the multi-stage treatment of FIGS. **11**A, **11**B, and **11**C in accordance with embodiments of the present disclosure.

FIG. **12**A schematically shows a well configuration according to first operational sequence in another multi-stage treatment according to embodiments of the disclosure.

FIG. **12**B schematically shows a well configuration according to second operational sequence in the multi-stage treatment of FIG. **12**A in accordance with embodiments of the present disclosure.

FIG. **12**C schematically shows a well configuration according to third operational sequence in the multi-stage treatment of FIGS. **12**A and **12**B in accordance with embodiments of the present disclosure.

FIG. **12**D schematically shows a well configuration according to a fourth operational sequence in the multi-stage treatment of FIGS. **12**A, **12**B, and **12**C in accordance with embodiments of the present disclosure.

DETAILED DESCRIPTION

Certain examples are shown in the above-identified figures and described in detail below. In describing these examples, like or identical reference numbers are used to identify common or similar elements. The figures are not necessarily to scale and certain features and certain views of the figures may be shown exaggerated in scale or in schematic for clarity and/or conciseness.

"Above", "upper", "heel" and like terms in reference to a well, wellbore, tool, formation, refer to the relative direction or location near or going toward or on the surface side of the device, item, flow or other reference point, whereas "below", "lower", "toe" and like terms, refer to the relative direction or location near or going toward or on the bottom hole side of the device, item, flow or other reference point, regardless of the actual physical orientation of the well or wellbore, e.g., in vertical, horizontal, downwardly and/or upwardly sloped sections thereof.

As used herein, an open zone, including an open fracture zone, refers to a zone in which there may be fluid communication between the formation and the wellbore extending through the formation. That is, such open zone may refer to an open hole or a section of an open hole (where no casing or liner is cemented in place, serving as a barrier between the formation and the wellbore), or to a cased well which has been modified to allow for such access to the formation. In one or more embodiments, such well may be a cased well with at least one perforation, perforation cluster, a jetted hole in the casing, a slot, at least one sliding sleeve or wellbore casing valve, or any other opening in the casing that provides communication between the formation and the wellbore.

Depth in when used in the present disclosure refer to any displacement or distance being horizontal, vertical or lateral.

Fracture shall be understood as one or more cracks or surfaces of breakage within rock. Fractures can enhance permeability of rocks greatly by connecting pores together, and for that reason, fractures are induced mechanically in some reservoirs in order to boost hydrocarbon flow. Fractures may also be referred to as natural fractures to distinguish them from fractures induced as part of a reservoir stimulation or drilling operation.

The term "fracturing" refers to the process and methods of breaking down a geological formation and creating a fracture, i.e. the rock formation around a well bore, by pumping fluid at very high pressures (pressure above the determined closure pressure of the formation), in order to increase production rates from a hydrocarbon reservoir. The fracturing methods otherwise use conventional techniques known in the art.

The term "treatment", or "treating", refers to any subterranean operation that uses a fluid in conjunction with a desired function and/or for a desired purpose. The term "treatment", or "treating", does not imply any particular action by the fluid.

Monitoring shall be understood broadly as a technique to track the effect of the treatment.

Survey include the measurement versus depth or time, or both, of one or more physical quantities in or around a well. In the present disclosure the term may be used interchangeably with logs.

As used herein, the terms "plug", "sealing agent" or "removable sealing agent" are used interchangeably and may refer to a solid or fluid that may plug or fill, either partially or fully, a portion of a subterranean formation. The portion to be filled may be a fracture that is opened, for example, by a hydraulic or acid fracturing treatment.

Isolating device in the present context include tools such as bridge plugs, cups or sealing elements such as packers.

Deploy shall be understood as running and potentially retrieve a tool in a wellbore. An example of conveyance mean suitable for deploying a toll may be a coiled tubing.

Leak off shall be understood as the fluid leaving the wellbore to enter in the formation. In shale formations, where the rock permeability is extremely small, the leak off requires a fracture which intersects the wellbore. In conventional formations, fluid may leak off in high permeability matrix of the rock such that zones which are not fractured may contribute to leak off

Logging shall be broadly interpreted as the operation of recording measurement in the wellbore.

Diverter in the present disclosure shall be understood as a chemical agent or mechanical device used in injection treatments, such as matrix stimulation, to ensure a uniform distribution of treatment fluid across the treatment interval. Injected fluids tend to follow the path of least resistance, possibly resulting in the least permeable areas receiving inadequate treatment. By using some means of diversion, the treatment can be focused on the areas requiring the most treatment. To be effective, the diversion effect should be temporary to enable the full productivity of the well to be restored when the treatment is complete. There are two main categories of diversion: chemical diversion and mechanical diversion. Chemical diverters function by creating a temporary blocking effect that is safely cleaned up following the treatment, enabling enhanced productivity throughout the treated interval. Mechanical diverters act as physical barriers to ensure even treatment.

Distributed measurement cable may be understood as a cable enabling to record changes along a well such as for example temperature changes. Such distributed measurement can be achieved using various devices, an example may be a fiber-optic cable. The distributed temperature is measured by sending a pulse of laser light down the optical fiber. Molecular vibration, which is directly related to temperature, creates weak reflected signals. Such type of devices also enables measuring flow rates by creating a temperature transient and observing its movement along the well.

Cable include cables on which tools are lowered into the well and through which signals from the measurements are passed.

An example cable for use in fracturing zones in a well includes a cable core that has an optical fiber conductor. The optical fiber conductor includes a pair of half-shell conductors. The half-shell conductors can be made from any conductive material. Illustrative conductive materials include copper, steel, or the like. The half-shell conductors can be used to provide data, power, heat or combinations thereof. The material of the conductors can be selected to accommodate the desired resistance of the cable. The half-shell conductors can be used to provide heat, and the heating of the cable can be controlled by selective adjustment of current passing through the half-shell conductors.

An insulated optical fiber is located between the pair of half-shell conductors. The insulated optical fiber can be insulated with a polymer or other insulating material. The insulated optical fiber can be coupled with the pair of half-shell conductors. For example, the insulation of the optical fiber can be bonded with the optical fiber and the inner surfaces of the half-shell conductors. Coupled as used herein can mean physically connected or arranged such that stress or force applied to the half-shell conductors is also applied to the optical fiber. For example, the space between the insulated optical fiber and the half-shell conductors can be minimal to allow coupling of the insulated optical fiber and half-shell conductors. The optical fiber can be a single optical fiber or a plurality of optical fibers. The optical fiber can be a bundle of optical fibers.

An optical fiber conductor jacket can be disposed about the pair of half-shell conductors. The optical fiber conductor jacket can be made from polymer or other materials.

An example cable core can also include a plurality of optical fiber conductors and cable components located in interstitial spaces between the plurality of optical fiber conductors. The cable components can be glass-fiber yarn, polymer, polymer covered metal tubes, composite tubes, metal tubes, or the like. A central cable component can be located between the plurality of optical fiber conductors. In one or more embodiments, a non-conductive material can be located in the cable core to fill void spaces therein.

A foamed-cell polymer, a core jacket, an outer jacket, or combinations thereof can be located about the cable core. The core jacket can be a polymer, a fiber reinforced polymer, a cabling tape, or combinations thereof.

In one or more embodiments, a seam-weld tube can be located about an outer jacket. The seam-welded tube can at least partially embed into the outer jacket.

FIG. **1** depicts a schematic of an optical fiber conductor. The optical fiber conductor **100** has a first half-shell conductor **110**, a second half-shell conductor **112**, an insulated optical fiber **114**, and an optical fiber conductor jacket **116**.

FIG. **2** depicts a cable for use in fracturing operations according to one or more embodiments. The cable **200** includes a plurality of optical fiber conductors **100**, a plurality of cable components **210**, a core jacket **220**, a non-conductive material **230**, a foamed-cell polymer **240**, an outer jacket **250**, and a seam-welded tube **260**.

The plurality of optical fiber conductors **100** and the plurality of cable components **210** are cabled about a central cable component **212**. The non-conductive material **230** is used to fill spaces or voids in the cable core during cabling. The core jacket **220** is extruded or otherwise placed about the plurality of optical fiber conductors **100**, the cable components **220**, the central cable component **212**, and the non-conductive material **230**.

The foamed-cell polymer **240** is placed about the core jacket **220**, and an outer jacket **250** is placed about the foamed-cell polymer **240**. A seam-welded tube **260** is placed about the outer jacket **250**. The seam-welded tube **260** can at least partially embed into the outer jacket **250**. For example, a weld bead can embed into the outer jacket **250**.

The cable **200** can be connected to a downhole tool and can be arranged to heat and power delivery. For example, a power source at surface can be connected with two of the optical fiber conductors **100**, such that one is positive and the other is negative, the third can be used for grounding or floating. The paths can be in a series loop for heating application, and when power needs to be delivered to downhole tools a switch can open the series conductor path and connect each path to designated tool circuit for power delivery.

The self-heating and power supply can be performed concurrently. For example, one conductor can be connected to positive terminal at a power supply at surface and to a designated tool circuit downhole, and another conductor can be connected to a negative terminal at the surface and to a designated tool circuit downhole. Accordingly, power can be delivered downhole and one of the conductor paths can be a return; in one embodiment, if the downhole tool is a tractor, the tractor can be stopped and the wheels closed allowing power to be delivered without movement and at same time the self-heating can occur.

FIG. **3** depicts a schematic of another cable for use in fracturing operations according to one or more embodiments. The cable **300** includes the plurality of optical fiber conductors **100**, the plurality of cable components **210**, the center component **212**, the core jacket **220**, the non-conductive material **230**, the foamed-cell polymer **240**, the outer jacket **250**, the seam-welded tube **260**, a reinforced jacket **310**, an additional jacket **320**, and an additional seam-welded tube **330**.

FIG. **4** depicts a schematic of a cable for use in fracturing operations according to one or more embodiments. The cable **400** includes a plurality of optical fiber conductors **100**, the plurality of cable components **210**, the core jacket **220**, a first jacket **420**, a first layer of strength members **410**, a second jacket **422**, a second layer of strength members **430**, a third jacket **424**, and a reinforced outer jacket **440**.

The plurality of optical fiber conductors **100** and the plurality of cable components **210** can be cabled about the central component **212**. The non-conductive material **230** is used to fill spaces or voids in the cable core during cabling. A core jacket **220** is extruded or otherwise placed about the plurality of optical fiber conductors **100**, the cable components **220**, the central cable component **212**, and the non-conductive material **230**. A first jacket **420** can be placed about the cable core jacket **220**. The first jacket **420** can be a reinforced polymer, a pure polymer, or the like.

The first layer of strength members **410** can be cabled about the first jacket **420**. The first layer of strength members **410** can at least partially embed into the first jacket **420**. A second jacket **422** can be placed about the first layer of strength members **410**. The second jacket **422** can at least partially bond with the first jacket **420**. A second layer of strength members **430** can be cabled about the second jacket **422**. The second jacket **422** can separate the first layer of strength members **410** from the second layer of strength members **430** from each other. The strength members in the first strength member layer and the second strength member layer can be coated armor wire, steel armor wire, corrosion resistant armor wire, composite armor wire, or the like.

A third jacket **424** can be placed about the second layer of strength members **420**. The third jacket **424** can bond with the second jacket **422**. A reinforced outer jacket **430** can be placed about the third jacket **424**.

The quad type cable can be connected to a tool string using a 1 by 1 configuration, a 2 by 2 configuration, or a 3 by 1 configuration. For example, a series loop can be formed by connecting two conductors to positive and two conductors to negative in a closed loop and a switching device can be used to open the loop and connect with the downhole tools. In another configuration two of the conductors can be looped for heat generation and two of the conductors can be connected to the downhole tools for power deliver; if the downhole tool is a tractor, the tractor can be stopped and the wheels closed allowing power to be delivered without movement and at same time the self-heating can occur.

In one example, two conductor paths can be connected to power at surface and a third to negative at surface, and each of the conductors can be connected to designated tool circuits downhole for power delivery using one of the conductive paths as a return.

FIG. **5** depicts cable according to one or more embodiments. The cable **500** includes one or more optical fiber conductors **100**, a double jacket **510**, wires **520**, an insulating layer **530**, a first jacket **540**, a first layer of strength members **550**, a second jacket **560**, a second layer of strength members **570**, a third jacket **580**, and an outer jacket **590**.

The optical fiber conductor **100** has the double jacket **510** located thereabout. The double jacket can include two polymers of differing strength. The wires **520** can be served helically over the double jacket **510**. The insulating layer **530** can be placed about the wires **520**. The insulating layer can be a polymer or like material. The first jacket **540** can be placed about the insulating layer. The first jacket **540** can be a fiber reinforced polymer.

The first strength member layer **540** can be cabled about the first jacket **540**. The first strength member layer **540** can at least partially embed into the first jacket **540**. The second jacket **560** can be placed about the first strength member layer **540**. The second jacket **560** can bond with the first jacket **540**.

The second layer of strength members **570** can be cabled about the second jacket **560**, and the second layer of strength members **570** can at least partially embed into the second jacket **560**.

The third jacket **580** can be placed about the second layer of strength members **570**. The third jacket **580** can bond with the second jacket **560**. The outer jacket **590** can be placed about the third jacket **580**. The outer jacket **580** can be a fiber reinforced polymer.

FIG. **6**A depicts an example system for monitoring fracturing operations according to one or more embodiments. The system **600** includes a cable **610** and a tool string **620**. The tool string **620** includes an anchoring device **622** and a logging tool **624**. The cable **610** can be any of those disclosed herein or a cable having an optical fiber conductor as described herein. The anchoring device **622** can be a centralizer, a spike, an anchor, or the like. The tool string **620** can have a flow meter and a tension measuring device.

The cable **610** and tool string **620** can be conveyed into a wellbore **630**. The wellbore **630** has a heel **632**, a plurality of zones **634**, and a toe **636**. The cable **610** and tool string **620** can be conveyed into the wellbore **630** using any method of conveyance, such as pump down, tractors, or the like. The tool string **620** can be stopped adjacent a first zone adjacent the heel **632**. Fracturing fluid can be pumped into the well to open the zone, and the cable **610** can be used to monitor the fracturing operation. After fracturing, diverter fluid can be provided to the well to plug the fractures. The tool string and cable can be conveyed further into the well towards the toe **636** and stopped at intermediate zones. At each of the zones the fracturing operations and diverting can be repeated.

Once all zones are fractured, the plugged fractures can be unplugged. The plugged fractures can be unplugged using now known or future known techniques. The tool string **620** and cable **610** can be left in the wellbore and the zones can be produced, and the logging tool **624** can be used to acquire data. In one or more embodiments, the logging tool **624** can acquire data before the zones are fractured, as the zones are fractured, after the zones are fractured, or combinations thereof.

FIG. **6***b* depicts another example system for use in well to perform operations on the well. The system includes a tool string **640**. The tool string **640** includes a tractor **642**, a logging tool **644**, a perforating gun or assembly **646**, and a plug **648**. The tool string **640** can include other equipment to perform additional downhole services. The downhole services can include intervention operations, completion operations, monitoring operations, or the like. A cable **650** can be connected with the tool string **640**. The cable **650** can be any of those disclosed therein or substantially similar cables.

FIG. **7** depicts an example method of fracturing zones in a well according to one or more embodiments.

The method **700** includes conveying a cable and tool string into a well to a first zone adjacent a heel of a horizontal portion of the well (Block **710**). As the cable and tool string are conveyed into the well, the tension on the cable and the flow of fluid can be measured. Fluid flow and cable tension can predict the cable status. For example, if a high flow rate is measured but the cable loses tension, it would indicate the cable is buckling or stuck downhole; if the cable is under tension and low or no flow is detected, the fractures before the cable anchoring mechanism are taking most of the fluid; if the cable is under tension and high flow rate is measured it would indicate that there are no open fractures before the cable anchoring mechanism and the cable should be moving towards the toe of the well. The fluid flow can be measured using a flow meter in the tool string or the self-heated capability of the cable can be used to predict the flow velocity around the cable based on the rate of increase or decrease of the temperature using distributed temperature sensing.

The method can also include anchoring the cable and tool string in the well (Block **720**). The method can also include applying fracturing fluid to the first zone (Block **730**).

The method also includes monitoring the fracturing by using an optical fiber conductor of the cable to acquire cable temperature data, temperature increase and decrease data, vibration data, strain data, or combinations thereof (Block **740**). The hydraulic fracturing process is monitored using the heat-enabled fiber-optic cable. Real-time measurements of cable temperature, temperature increase or decrease rate, vibration, and strain measurements are available to predict which fracture is taking more fluid.

Operations above can be repeated for each zone. Cable tension measurement and fluid flow can be monitored after each zone to prevent damage to the cable.

FIG. **8** depicts an example method of placing a cable in well for monitoring. The method **800** includes conveying a cable and tractor into a well (Block **810**). The conveying can be performed using pump down, a tractor, gravity, other known or future known methods, or combinations thereof.

Once the tractor and at least a portion of the cable or located at a desired location in the well, the method can include anchoring the tractor in place (Block **820**). The tractor can be anchored in place using anchoring spikes, anchoring pads, or the like.

The method can also include removing slack from the cable after the tractor is anchored in place (Block **830**). The slack can be removed from the cable by pulling at the surface or using other known or future know techniques.

The method can also include monitoring the well conditions, operation parameters, or combinations thereof. The monitoring can include hydraulic fracturing monitoring, detecting leaks in a casing, gas production, oil production, electrical submersible pump monitoring, gas lift mandrel monitoring, injection water breakthrough, cross flow shut-in, gas breakthrough, injection profile of water injection wells, steam injection monitoring, CO2 injection performance, zonal isolation monitoring, monitoring for flow behind casing, or other temporary or permanent monitoring operations. The cable can acquire data to aid in fracture height determination, zonal flow contribution determination, evaluation of well stimulation, optimization of gas lift operations, optimization of electrical submersible pumps, other wellbore data, operation data, or production data, or combinations thereof.

The monitoring can be performed in any type of well. Illustrative wells include subsea wells, vertical wells, and horizontal wells. The monitoring can be permanent monitoring or temporary monitoring.

FIG. **9** depicts an example method of placing a cable in a well for hydraulic fracturing and logging in a horizontal well. The method **900** includes connecting the cable with a plug, tractor, and logging tool (Block **910**). The plug can be a packer or other sealing device. The tractor can be battery operated or powered by the cable.

The method **900** also includes conveying the tractor, plug, and logging tool to a desired location within a well (Block **920**). The desired location can be any location in the well. The desired location can be at the toe of a horizontal portion of the well, within an intermediate location of a horizontal portion of the well, or any other portion of the well.

The method also includes anchoring the tractor and removing slack from the cable (Block **930**). The method also includes setting the plug (Block **940**). The plug can isolate the tractor and logging tool from pressure in the well, corrosive fracturing fluids, or other wellbore condition uphole of the tractor and logging tool. The method includes pumping fracturing fluid into the well (Block **950**). The method also includes monitoring the fracturing operation using the cable (Block **960**). The monitoring can include obtaining real-time measurements of cable temperature, temperature increase or decrease, vibration, strain measurement, or other parameters.

The method also includes pumping diverter fluid into the well (Block **950**). The method also includes repeating the fracturing and pumping of divert fluid until desired state of production is obtained (Block **970**). The method also includes deactivating the plug and reversing the tractor out of the well (Block **980**). The method also includes logging with the logging tool as the tractor is reversed out of the well (Block **990**).

In one or more embodiments of the method, the method can also include monitoring production with the cable as the tractor is reversed out of the well.

In one or more embodiments of the methods disclosed herein the cable can be connected with the tractor, a perforating gun, a logging tool, or combinations thereof. For example, the cable can be connected with a perforating gun and tractor, and the perforating gun can be used to perforate the well before the well is fractured. In another example, the cable can be connected with a perforating gun, tractor, logging tool, and a plug. The well can be perforated, the plug can be set, fracturing operations carried out, and logging can be performed as the tractor is reversed out of the well. Of course, other combinations of downhole hole equipment can be added to the tool string allowing for real-time monitoring using the cable and performance of multiple operations to be performed on a well in a single trip.

FIG. **10** depicts an example cable for monitoring in a well. The cable **1000** can include a cable core that includes a plurality of conductors **1100** and a plurality of cable components **1200**. The conductors **1100** can be any conductor. Illustrative conductors include stranded conductors, fiber optic conductors, other conductors described herein, other know or future known conductors, or combinations thereof. The cable components **1200** can be filler rods, incompressible polymer rods, metallic rods, other now known or future known components, or any combination thereof.

The cable core can have a first armor layer **1300** and a second armor layer **1400** disposed thereabout. The armor layers **1300** and **1400** can include any number of armor wires. The armor layers can be filled with polymer, and the polymer in each armor layer can be bond together. In one or more embodiments, a jacket or the like can separate the first armor layer **1300** from the second armor layer **1400**.

For a hepta cable the cable can be connected with the downhole tool in surface power supply using a 3 by 3 configuration. Three conductors can be used for power delivery and 3 conductors can be used for heating. Other configuration can be used. For example, all conductors can be used for heating by connecting in loop, where three conductors are connected to positive of power supply and three conductors are connected to negative of the power supply, and at the tool string a switch can be used to open the loop and connect the conductors to the a designated circuit for power delivery.

In another embodiment, power delivery and heating can be done at the same time. For example, three conductors can be connected to positive at the surface and three conductors can be connected to negative at surface, two or more conductors can be in series for heating application, and the remaining conductive paths can connected to designated tool circuit for power delivery using one conductive path as the return; and when the tractor is stopped the wheels can be retracted allowing for power delivery while avoiding movement.

The cables disclosed herein can be connected with downhole tools and surface power in various ways allowing for continuous power delivery and heating, selective power delivery and heating, or combinations thereof. The connections can be made using now known or future known techniques. The connections can include switches, microprocessors, or other devices to control power delivery and heating.

In some embodiments the disclosure herein relates generally to multi-stage well treatment methods and systems for treating a subterranean formation, using an isolating device tethered with a distributed measurement cable during the treatment of one or more stages.

In some embodiments of the present disclosure, a method for multi-stage well treatment comprises: (a) perforating a first interval in the well above a first target depth; (b) deploying to the first target depth an isolation object tethered to a distributed measurement cable from the surface; (c) isolating the well at the first target depth with the isolation object; (d) treating the first perforated interval in a plurality of stages; and (e) receiving measurements from the distributed measurement cable for monitoring each stage of the treatment, which may optionally be concurrent with the treatment in (d).

In some embodiments, the method may further comprise detaching the distributed measurement cable from the isolation object, and removing the distributed measurement cable from the well. In some embodiments, the method may further comprise leaving the distributed measurement cable in the well, initiating production from the first treated interval and concurrently obtaining measurements from the distributed measurement cable to monitor the production.

In some embodiments, the method may further comprise repeating the perforation (a), deployment (b), isolation (c), treatment (d), and monitoring (e), one or more times with respect to successive intervals above successively higher target depths.

In some embodiments, the method may further comprise treating a stage below the first target depth prior to treatment of the first interval. In some embodiments, the stage below the first target depth is treated prior to perforating the first interval. In some embodiments, treating the stage below the first target depth comprises actuating a rupture disk valve. In some embodiments, the method may further comprise installing the rupture disk valve with a casing string. In some embodiments, treating the stage below the first target depth comprises deploying one or more perforating guns below the first target depth to initiate fluid entry into the stage below the first target depth.

In some embodiments, the method may further comprise installing a retention sub with a casing string at the first target depth. In some embodiments, the method may further comprise installing a landing seat in the retention sub to receive the isolation object, such as, for example, installing the landing seat with a wireline. In some embodiments, the method may further comprise concurrently conveying a landing seat installation tool to the retention sub and a perforating tool to the first interval, with the wireline, e.g., on the same wireline.

In some embodiments, the isolation object comprises a degradable ball. In some embodiments, the method may further comprise removing the isolation object.

In some embodiments, the method may further comprise determining the first target depth using an optimization algorithm based on reservoir quality (RQ) and completion quality (CQ) indexes such as the ones disclosed in SPE 146872 and/or US20130270011.

In some embodiments, the measurements received are selected from fluid flow rate, distributed temperature, distributed vibration, distributed pressure, and combinations thereof. In some embodiments, the treatment (d) comprises fracturing, such as, for example, pumping a treatment fluid comprising proppant laden stages separated by one or more diverter pills. In some embodiments, the method may further comprise adjusting in (d) one or more of respective sizes of the proppant laden stages, number of the diverter pills, and volumes of the diverter pills, in response to the measurements received in (e). In some embodiments the measurements obtained comprise fluid flow rate versus depth during the treatment to monitor fluid flow into the one or more open fracture zones in the interval. In some embodiments, for example, the treatment comprises diverting a fracturing treatment fluid by placing a plug or seal in at least one of the one or more open fracture zones located in the target interval, and wherein the measurement of the fluid flow rate versus depth indicates the effectiveness of the plug/seal, and/or further comprising reinforcing the plug/seal if the it is indicated to be ineffective. In some other embodiments, the cable gathers distributed measurement information to monitor the degradation of one or more degradable diverter plugs or seals placed during the treatment; for example, the cable can gather distributed measurement information to determine if at least one of the one or more degradable diverter plugs or seals has been adequately degraded, and the operational sequence can then progress to introducing a fracturing fluid into the at least one or more unplugged open fracture zones wherein the corresponding diverter plug(s) or seal(s) has been determined to have been degraded.

In some embodiments, the fracturing treatments in (d) comprise sealing at least one open zone of the respective interval with at least one removable sealing agent, selectively removing the removable sealing agent from at least one target zone, and fracturing the at least one target zone, e.g., where the fracturing treatments in (d) occur while at least one open zone of the well is sealed with at least one removable sealing agent. In some embodiments, at least one of: sealing at least one open zone of the interval with at least one removable sealing agent, selectively removing the removable sealing agent from the at least one target zone, or the fracturing of the at least one target zone, is repeated at least one time.

In some embodiments, the method may further comprise sealing the fractured target zone with at least one removable sealing agent. In some embodiments, the the selective removing comprises at least one of perforating, abrading, dissolving, hydrolyzing, oxidizing, degrading, or melting the removable sealing agent from at least one sealed target zone. In some embodiments, the selective removal of the removable sealing agent comprises contacting the at least one target zone with a removal agent by bullheading the removal agent downhole, spotting the removal agent downhole, the use of downhole containers to deliver the removal agent, or a combination thereof. In some embodiments, the removal agent dissolves the removable sealing agent; and wherein the removal agent is at least one of hydrochloric acid, formic acid, acetic acid, hydroxides, ammonia, organic solvents, diesel, oil, water, brines, solutions of organic or non-organic salts, and mixtures thereof.

In some embodiments, the fracturing treatments comprise at least one of a propped fracturing, a non-propped fracturing, a slick-water, acidizing, acid fracturing, injection of chelating agents, stimulating, or squeezing a chemical.

In some embodiments, the removable sealing agent comprises a viscous fluid from at least one of gelled water, viscoelastic surfactant fluids, crosslinked polymer solutions, slick-water, foams, emulsions, dispersions of acid soluble solid particulates, dispersions of oil-soluble resins, and the like, and mixtures thereof. In some embodiments, the removable sealing agent comprises a solid material comprising at least one of acid soluble cement, calcium carbonate, magnesium carbonate, polyesters, magnesium, aluminum, zinc, and their alloys, hydrocarbons with greater than 30 carbon atoms, and carboxylic acids, and the like and derivatives and combinations thereof. In some embodiments, the removable sealing agent comprises manufactured shapes selected from at least one of particulates, sized particulates, fibers, flakes, rods, pellets, and the like, and combinations thereof. In some embodiments, the removable sealing agent comprises a degradable composite material comprising a degradable polymer mixed with particles of a filler material.

In some embodiments, the sealing comprises placing the removable sealing agent in a desired zone in the wellbore by at least one of bullheading the removable sealing agent downhole, spotting the removable sealing agent downhole, or using downhole containers to deliver the removable sealing agent. In some embodiments, the sealing further comprises injecting the sealing material into the selected zone by increasing pressure in the well. In some embodiments, at least one seal of the sealed zones is mechanically strengthened by compacting the seal with an epoxy resin gluing system or an emulsion comprising wax or paraffin.

In some embodiments, at least two zones are sealed with two distinct removable sealing agents which possess the capability of being removed by dissimilar removal processes.

In some embodiments, the method further comprises sealing the fractured zone(s) by at least one of plugging of perforations and/or well or annulus space between a casing and a borehole, reducing permeability of formation rock, modifying the stress field, or changing formation fluid pressure.

In some embodiments, the fracturing treatments in the respective intervals comprise: isolating, or sealing with a removable sealing agent, or a combination thereof, all but one of a plurality of open zones in the respective interval; fracturing the open zone while the other zones in the respective interval are isolated or sealed or a combination thereof; sealing the fractured zone or isolating the section of the respective interval comprising the fractured zone; selectively removing the removable sealing agent from an untreated sealed zone; and repeating the sequence of fracturing the open zone while the other zones are isolated or sealed, isolating or sealing the fractured zone, and selectively removing the removable sealing agent from a sealed un-fractured zone until the desired number of zones are re-fractured.

In some embodiments of the present disclosure, the method for multi-stage well treatment comprises: (a) installing in a casing string an initiation sub adjacent a toe of the well; (b) installing in the casing string a plurality of retention subs at a first target depth and one or more successively higher target depths above the initiation sub; (c) actuating the initiation sub to treat a stage adjacent the initiation sub; (d) perforating a first interval in the well above the first target depth; (e) deploying to the first target depth an isolation object tethered to a distributed measurement cable from the surface; (f) seating the isolation object deployed in (e) in the retention sub installed at the first target depth to isolate the well at the first target depth; (g) treating the first perforated interval in a plurality of stages; (h) concurrently receiving measurements from the distributed measurement cable for monitoring each stage of the treatment in (g); (i) detaching the distributed measurement cable from the isolation object seated in (f); (j) repeating at least the perforation in (d), the deployment in (e), the seating in (f), the treatment in (g), and the monitoring in (h), one or more times with respect to successively higher intervals above the respective one or more successively higher target depths. In some embodiments, each iteration of the repetition in (j) further comprises the detaching in (i) and removing the distributed measurement cable from the well. In some embodiments, the initiation sub comprises a rupture disk valve and the actuation in (c) comprises bursting the rupture disk valve.

In some embodiments, the method further comprises: (k) concurrently conveying landing seat installation tools to the respective retention subs, and perforating tools to the respective intervals, with a wireline; and (l) installing landing seats with the respective landing seat installation tools in the respective retention sub to receive the respective isolation objects. In some embodiments, the method further comprises removing the isolation objects, e.g., prior to perforation and/or treatment of a successive interval.

In some embodiments, the method may further comprise determining the first and successively higher target depths using an optimization algorithm based on reservoir quality (RQ) and completion quality (CQ) indexes indexes such as the ones disclosed in SPE 146872 and/or US20130270011.

In some embodiments, the measurements received are selected from fluid flow rate, distributed temperature, distributed vibration, distributed pressure, and combinations thereof.

In some embodiments, the treatments in (c) and (g) comprise fracturing treatments. In some embodiments, the fracturing treatments in (g) comprise pumping a treatment fluid comprising proppant laden stages separated by one or more diverter pills. In some embodiments, the method further comprises adjustment during the fracturing treatments in (g) one or more of respective sizes of the proppant laden stages, number of the diverter pills, and volumes of the diverter pills, in response to the measurements received in (h).

In some embodiments, the fracturing treatments in (g) comprise sealing at least one open zone of the respective interval with at least one removable sealing agent, selectively removing the removable sealing agent from at least one target zone, and fracturing the at least one target zone, including any of the zone sealing embodiments discussed above.

In further aspect, embodiments of a system for multi-stage well treatment comprise: (a) a perforating system to convey a perforating device to perforate an interval in the well above a target depth; (b) a deployment system to deploy an isolation object tethered to a distributed measurement cable from the surface to the target depth and isolate the well at the first target depth with the isolation object; (c) an interval treatment system to treat the perforated interval with a treatment fluid in a plurality of stages; and (d) a distributed measurement collection system to receive and interpret measurements from the distributed measurement cable during the treatment to monitor the plurality of the treatment stages.

In some embodiments, the perforating, deployment, treatment and distributed measurement collection systems are operable to repeat the perforation, deployment, treatment, and measurement interpretation with respect to one or more successively higher target depths and respective intervals.

In some embodiments the system may further comprise an initiation sub installed in a casing string at a toe of the well to treat a stage below the target depth before deployment of the isolation object to the target depth, such as, for example, a rupture disk valve comprising a plurality of rupture disks operatively associated with respective helical slots.

In some embodiments, the distributed measurement cable comprises a fiber optic sensing system.

In some embodiments the system may further comprise one or more retention subs installed in a casing string at one or more of the target depths; and/or a wireline system comprising an installation tool to install landing seats for the isolation object at each respective retention sub. In some embodiments the wireline system is operable with the perforating system to convey the installation tool and the perforating device on a common wireline.

In some embodiments the isolation object comprises a degradable ball.

In some embodiments the system may further comprise a software module to determine the target depth using an optimization algorithm based on reservoir quality (RQ) and completion quality (CQ) indexes such as the ones disclosed in SPE 146872 and/or US20130270011.

In some embodiments of the system, the treatment fluid comprises a fracturing fluid, such as, for example, proppant laden stages separated by one or more diverter pills. In some embodiments the system may further comprise a treatment control module to adjust one or more of respective sizes of the proppant laden stages, number of the diverter pills, and volumes of the diverter pills, in response to the measurements interpreted by the distributed measurement collection system.

In some embodiments of the system, the treatment fluid may comprise at least one removable sealing agent to seal at least one open zone of the interval, a removal agent to selectively remove the removable sealing agent from at least one target zone, and a fracturing fluid to treat the at least one target zone.

With reference to FIGS. **11**A-**11**D, well configurations according to some embodiments of an operational sequence are schematically illustrated. In FIG. **11**A, a well **10** is shown following identification of a target depth **12** at which a retaining sub **14** may optionally have been installed, e.g., by running it in the hole with the optional casing **16** during placement thereof, or installing it in an open hole completion, or as a retrofit after installation of the casing. Although described in reference to a cased completion for the purpose of illustration and not by way of limitation, the principles of the present disclosure are likewise applicable to an open hole completion and/or a partially cased completion.

In some embodiments, the target depth is determined using an optimization algorithm based on reservoir quality (RQ) and completion quality (CQ) indexes, such as described in, for example SPE 146872, US20130270011, each of which is incorporated fully herein by reference. Software modules and/or target depth determination services are commercially available, for example, under the trade designations MANGROVE, COMPLETION ADVISOR available from SCHLUMBERGER, and the like. According to some embodiments, the corresponding treatment intervals can be relatively large, e.g., 150 meters or more.

The retaining sub **14**, according to some embodiments, as mentioned, is optional, e.g., when the isolation object **18** (see FIG. **11**C) is a self-setting isolation tool or device, or otherwise capable of sealing directly to an inside surface of the casing **16**. According to some embodiments, the retaining sub **14** may be designed specifically for operability with the type of isolation object **18** to be used. One representative example of a retaining sub **14** is disclosed in U.S. Pat. No. 9,033,041, US application 2014-0014371 or US application 2014-0202708, which is designed to seat a retaining ring **104** (see FIG. **12**B) Other suitable retaining subs **14** are commercially available might be used.

With reference to FIG. **11**B, in the next operational sequence according to some embodiments, a perforating gun **20** or other suitable perforation device is deployed in the well **10** to perforate a plurality of perforation zones **22**, **24**, **26** in the interval **28**. Suitable perforation devices are described for example in U.S. Pat. No. 6,543,538 which is hereby fully incorporated herein by reference. The perforating gun **20** may be conveyed to the interval **28** via wireline **30**, or in some embodiments is conveyed by coiled tubing, tractor, pump-down system, self-propulsion, or the like. After perforating the interval **28**, the perforating gun **20** may be removed from the interval **28** and/or the well **10**, and/or may be relocated to the next interval to be treated, another location in the well **10** until needed again, or to the surface, or the like.

With reference to FIG. **11**C, in the next operational sequence according to some embodiments, the isolating object **18** is shown tethered to the distributed measurement cable **32** and deployed to seat in the retaining sub **14** or otherwise at the target depth **12** to isolate the interval **28** from a portion of the well below the target depth **12**. The isolating object **18** may be any suitable device, tool, material or other item capable of effecting isolation, such as, for example, a ball, dart, packer, cups, or the like. In some embodiments, the isolation object **18** is pumped into the well **10** via a surface pump-down deployment system **34**, which may include a truck and/or skid mounted unit or units for pumping, mixing, control, etc., for example. As motive fluid is pumped from the surface behind the tool **18**, it is pushed down to the target depth **12** of the well **10** for seating in the retaining sub **14**.

In some embodiments, the isolation object **18** is degradable or otherwise removable, such as, for example, a dissolvable dart, or degradable ball. Degradable balls have increasingly found their way into open-hole graduated ballseat systems for use in multi-stage stimulation. Schlumberger's ELEMENTAL system, for example, is comprised of a metallic degradable material which can accommodate high differential pressures, as well as high static and dynamic contact stresses. The use of these balls can improve reliability of the ballseat system, and may eliminate the need for interventions such as coiled tubing milling. One advantage of using degradable metals for frac balls is that they may avoid failure mechanisms such as, for example, balls getting stuck in their seats or severely deforming, because the balls degrade over time and thus remove the temporary obstruction effected by the ball with respect to the lower zones of the well. Degradable materials can be selected by one skilled in the art to accommodate the completions practice of the present disclosure due to their significant working range of pressure and temperature.

Suitable degradable isolation objects are described for example in SPE 166528, which is hereby fully incorporated herein.

In some embodiments the cable **32** may be a distributed measurement cable as disclosed herein.

With reference to FIG. **11**D, in the next operational sequence according to some embodiments, the isolation object **18** is tightly set to isolate the interval **28** from the lower section of the well **10**, which may contain additional zones or fractures treated in a previous treatment operation or cycle, and the interval **28** can then be treated with an appropriate treatment fluid pumped into the interval **28** above the activated isolating object **18**. In some embodiments, the interval **28** is treated by injecting a fracturing treatment fluid simultaneously or sequentially via the perforation zones **22**, **24**, **26** (see FIG. **11**A) to form respective fracture zones **36**, **38**, **40**, using one or more treatments available for fracturing an interval of a well as discussed hereafter.

Where the cable **32** is provided with distributed measurement functionality in some embodiments, measurement information gathered along the length thereof may be used during the fracturing or other treatment for monitoring of the fracturing treatment while (real-time) it is being executed, or afterwards. For example, the cable **32** can be used in some embodiments to measure the fluid flow rate as a function of depth, information which can be used to monitor the volume and/or rate at which each fracture **36**, **38**, **40** receives treatment fluid during the fracturing or other treatment, e.g., the manner in which the treatment fluid redistributes along the treated interval as the net pressure in each fracture zone varies and influences the flow profile; or the effectiveness of a seal, plug or diverter that may be located and/or removed at the fracture as part of the treatment process. Such information in some embodiments can facilitate adjustments to the treatment pumping or composition schedule, including the pumping rate and/or pressure, e.g., in fracturing treatments which use a diverter, where the effectiveness of the diverter at the plugged fractures can be monitored and corrective actions can be taken in response to the measurements observed during the treatment. For example, in some embodiments where excessive leakage is detected into a fracture zone at which diverter has been placed, an additional diverter treatment and/or diverter reinforcement treatment may be pumped to the fracture zone in question.

In some embodiments, the degradation of any diversion material in the one or more of the perforation zones **22**, **24**, **26** can be monitored by maintaining a positive pressure from wellbore **10** and monitoring the profile of fluid flow, e.g., via the distributed measurement cable **32**, during the process of degradation of the diverting material. In some embodiments, once it is determined and/or confirmed via distributed measurement cable **32** that the perforation zones which are desired to be treated, are opened again by removal of the respective plugs, then the material in the plugs can be considered sufficiently degraded such that the respective perforation zones **22**, **24** and/or **26** are ready for initiation of the fracturing treatment and/or other receipt of treatment fluid to form the corresponding fracture zones **36**, **38**, **40**.

In the case of fracturing treatments according to some embodiments herein, the number of stages and depth of stages in the interval **28** may vary according to different embodiments, and if desired, depths and/or pumping schedules can be varied in response to information acquired with the monitor cable **32**, e.g., in real time. In one or more embodiments, examples of sources of the information used for making such decisions may comprise magnitude of the treating pressure, temperature log data, microseismic including real-time microseismic data, or any other known sources of information that may be beneficial to the decision making process. In any of the embodiments discussed herein, this process may then be repeated until completion of the desired number of stages in the interval **28** and formation of the fracture zones **36**, **38**, **40**, e.g., toe-to-heel (**40**, **38**, **36**), or heel-to-toe (**36**, **38**, **40**), or a combination thereof.

In any of the embodiments discussed herein, once all stages are completed, the monitor cable **32** may be placed or left at least temporarily at a desired depth in the well **10**, e.g., along the length of any treated or other zones to be produced, while production flow back is initiated (or longer if desired), and the monitor cable **32** can be used to collect data to determine a production flow profile. In these embodiments, the cable **32** can be placed or left in the well **10** at least until such time as the production monitor service is no longer required, or can be placed or left in the well **10** for later re-establishment of production monitoring.

Suitable multi-stage interval treatment systems and methods using diverter materials are described in SPE 169010, and U.S. Pat. No. 8,905,133, which are hereby fully incorporated herein by reference.

In some embodiments disclosed herein the plugs used to seal the pre-existing and/or newly created fractures and the methods of using them may involve controllable and/or selective chemical induced zonal sealing/unsealing for treatment diversion during multistage well stimulation operations, such as, for example, dividing the wellbore **10** into multiple zones, e.g., well sections, plugging at least one fracture zone with one or more various removable sealing agents, then selectively removing the sealing agents and unsealing one or more previously sealed zones so that the unsealed zone(s) may be treated.

The embodiments of methods for selective zonal sealing/unsealing for treatment diversion between the stages of a multi-stage well presented herein are applicable for stimulating wells regardless of their completion type. The selectivity of the zonal sealing/unsealing as used herein may be conferred by either selective placement or selective reaction. Selective placement may involve selecting the location at which the sealing agent is applied or removed, which may be enabled by placing a tool at the depth where the sealing or removing takes place. For example, a coiled tubing line spotted at the depth where the sealing agent is to be removed may then use abrasive jet perforating to perforate through the seal or to spot a chemical capable of removing the seal. Selective reaction may involve a selective degradation time for the sealing agent or a selective chemical agent for removing selected sealing agents. In some embodiments, selective degradation may occur via a sealing agent degrading at a faster rate in the presence of a certain wellbore fluid or chemical than another sealing agent used to seal the wellbore. Selective reaction and removal of a sealing agent may occur when a chemical removing agent reacts or interacts with certain sealing agents while being substantially inert towards other sealing agents. For example, the chemical removing agent may react or interact to induce hydrolysis, oxidation, dissolution, and/or degradation of the sealing agent.

If further treatments of different zones of the wellbore are warranted or desired, the treated target zone of the wellbore may optionally be sealed with at least one or more removable sealing agents. It is another possibility to leave the treated target zone unsealed. The removable sealing agents sealing the next target zone(s) may be selectively removed to enable treatment of the next target zone(s). In this way, the treatment of the desired wellbore zone may be completed by repeating the process as many times as desired. Eventually, if no further treatments are warranted or desired, a final selective removal of at least one of the removable sealing agents in the sealed zones may be performed to reach the end of the job and allow for production through the wellbore.

As mentioned, the method may begin with a well having at least one zone open. In one or more embodiments, the well may not initially contain an open zone or may not contain an open zone in a desired portion of the well, and the open zone may be created by perforating the casing with perforating charges, jetting with a coiled tubing (CT) line or slick-line conveyed tools, cutting the casing, or any other known methods for creating an open zone in a well. In some embodiments, manipulating at least one sliding sleeve or wellbore casing valve within the wellbore or the creation of an open zone within a wellbore may enable access to an untreated zone of the formation.

At least one open zone may be sealed (temporarily) with a removable sealing agent that may be a dissolvable or otherwise removable composition. As used herein, sealing of an open zone (or zones) may involve reduction of a fluid's ability to flow from the wellbore into the open zone, which may include reduction in the permeability of the zone. As used herein, sealing an open zone refers to sealing the open zone at the sandface and does not involve plugging the wellbore itself, which is referred to instead as isolation of the wellbore. In particular, isolation may be used to isolate an entire section of the wellbore from any treatment or operations occurring in more upstream sections of the wellbore, whereas sealing, as used herein, leaves the wellbore open and instead seals the sandface.

The removable sealing agents may be any materials, such as solid materials (including, for example, degradable solids and/or dissolvable solids), that may be removed within a desired period of time. In some embodiments, the removal may be assisted or accelerated by a wash containing an appropriate reactant (for example, capable of reacting with one or more molecules of the sealing agent to cleave a bond in one or more molecules in the sealing agent), and/or solvent (for example, capable of causing a sealing agent molecule to transition from the solid phase to being dispersed and/or dissolved in a liquid phase), such as a component that changes the pH and/or salinity within the wellbore. In some embodiments, the removal may be assisted or accelerated by a wash containing an appropriate component that changes the pH and/or salinity. The removal may also be assisted by an increase in temperature, for example, when the treatment is performed before steam flooding, and/or a change in pressure.

In some embodiments, the removable sealing agents may be a degradable material and/or a dissolvable material. A degradable material refers to a material that will at least partially degrade (for example, by cleavage of a chemical bond) within a desired period of time such that no additional intervention is used to remove the seal. For example, at least 30% of the removable sealing agent may degrade, such as at least 50%, or at least 75%. In some embodiments, 100% of the removable sealing agent may degrade. The degradation of the removable sealing agent may be triggered by a temperature change, and/or by chemical reaction between the removable sealing agent and another reactant. Degradation may include dissolution of the removable sealing agent.

For the purposes of the disclosure, the removable sealing agents may have a homogeneous structure or may also be non-homogeneous including porous materials or composite materials. A removable sealing agent that is a degradable composite composition may comprise a degradable polymer mixed with particles of a filler material that may act to modify the degradation rate of the degradable polymer. In some embodiments, the particles of a filler material may be discrete particles. The particles of the filler material may be added to accelerate degradation and the filler particles may be from 10 nm to 5 microns in mean average size. In some embodiments, smaller filler particles may further accelerate degradation in comparison to larger filler particles. The filler particles may be water soluble materials, include hygroscopic or hydrophilic materials, a meltable material, such as wax, or be a reactive filler material that can catalyze degradation, such as a filler material that provides an acid, base or metal ion. In some embodiments, the filler particles may have a protective coating, thus allowing them to be mixed with a degradable polymer and/or heated during manufacturing processes, such as extrusion, whilst retaining their structural and compositional characteristics, the structural and compositional characteristics of the degradable polymer, and their capability for degradation. The coatings can also be chosen to delay degradation or fine tune the rate of degradation for particular conditions.

Examples of water soluble filler materials comprise NaCl, ZnCl2, CaCl2, MgCl2, NaCO3, KCO3, KH2PO4, K2HPO4, K3PO4, sulfonate salts, such as sodium benzenesulfonate (NaBS), sodium dodecylbenzenesulfonate (NaDBS), water soluble/hydrophilic polymers, such as poly (ethylene-co-vinyl alcohol) (EVOH), modified EVOH, SAP (super absorbent polymer), polyacrylamide or polyacrylic acid and poly(vinyl alcohols) (PVOH), and the mixture of these fillers. Examples of filler materials that may melt under certain conditions of use include waxes, such as candelilla wax, carnauba wax, ceresin wax, Japan wax, microcrystalline wax, montan wax, ouricury wax, ozocerite, paraffin wax, rice bran wax, sugarcane wax, Paricin 220, Petrac wax 165, Petrac 215, Petrac GMS Glycerol Monostearate, Silicon wax, Fischer-Tropsch wax, Ross wax 140 or Ross wax 160. Examples of reactive filler materials that may accelerate degradation include metal oxides, metal hydroxides, and metal carbonates, such as Ca(OH)2, Mg(OH)2, CaCO3, Borax, MgO, CaO, ZnO, NiO, CuO, Al2O3, a base or a base precursor. The degradable composites may also include a metal salt of a long chain (defined herein as C8) fatty acids, such as Zn, Sn, Ca, Li, Sr, Co, Ni, K octoate, stearate, palmate, myrisate, and the like. In some embodiments, the degradable composite composition comprises a degradable PLA mixed with filler particles of either i) a water soluble material, ii) a wax filler, iii) a reactive filler, or iv) combinations thereof, said degradable composite may degrade in 60° C. water in less than 30, 14 or 7 days.

Solid removable sealing agents for use as the sealing agent may be in any suitable shape: for example, powder, particulates, beads, chips, or fibers, and may be a combination of shapes. When the removable sealing agent is in the shape of fibers, the fibers may have a length of from about 2 to about 25 mm, such as from about 3 mm to about 20 mm. In some embodiments, the fibers may have a linear mass density of about 0.111 dtex to about 22.2 dtex (about 0.1 to about 20 denier), such as about 0.167 to about 6.67 dtex (about 0.15 to about 6 denier). Suitable fibers may degrade under downhole conditions, which may include temperatures as high as about 180° C. (about 350° F.) or more and pressures as high as about 137.9 MPa (about 20,000 psi) or more, in a duration that is suitable for the selected operation, from a minimum duration of about 0.5, about 1, about 2 or about 3 hours up to a maximum of about 24, about 12, about 10, about 8 or about 6 hours, or a range from any minimum duration to any maximum duration.

The removable sealing agents may be sensitive to the environment, so dilution and precipitation properties may be taken into account when selecting the appropriate removable sealing agents. The removable sealing agent used as a sealer may survive in the formation or wellbore for a sufficiently long duration (for example, about 3 hours to about 6 hours). The duration may be long enough for wireline services to perforate the next pay sand, subsequent fracturing treatment (s) to be completed, and the fracture to close on the proppant before it completely settles, providing an improved fracture conductivity.

Further suitable removable sealing agents and methods of use thereof include those described in U.S. Patent Application Publication Nos. 2006/0113077, 2008/0093073, and 2012/0181034, the disclosures of which are incorporated by reference herein in their entireties. Such removable sealing agents include inorganic fibers, for example of limestone or glass, but are more commonly polymers or co-polymers of esters, amides, or other similar materials. They may be partially hydrolyzed at non-backbone locations. Any such materials that are removable (due in-part because the materials may, for example, degrade and/or dissolve) at the appropriate time under the encountered conditions may also be employed as removable sealing agents in the methods of the present disclosure. For example, polyols containing three or more hydroxyl groups may be used. Suitable polyols include polymeric polyols that solubilizable upon heating, desalination or a combination thereof, and contain hydroxyl-substituted carbon atoms in a polymer chain spaced from adjacent hydroxyl-substituted carbon atoms by at least one carbon atom in the polymer chain. The polyols may be free of adjacent hydroxyl substituents. In some embodiments, the polyols have a weight average molecular weight from about 5000 to about 500,000 Daltons or more, such as from about 10,000 to about 200,000 Daltons.

Further examples of removable sealing agents include polyhdroxyalkanoates, polyamides, polycaprolactones, polyhydroxybutyrates, polyethyleneterephthalates, polyvinyl alcohols, polyethylene oxide (polyethylene glycol), polyvinyl acetate, partially hydrolyzed polyvinyl acetate, and copolymers of these materials. Polymers or co-polymers of esters, for example, include substituted and unsubstituted lactide, glycolide, polylactic acid, and polyglycolic acid. For example, suitable removable materials for use as plugging agents include polylactide acid; polycaprolactone; polyhydroxybutyrate; polyhydroxyvalerate; polyethylene; polyhydroxyalkanoates, such as poly[R-3-hydroxybutyrate], poly [R-3-hydroxybutyrate-co-3-hydroxyvalerate], poly[R-3-hydroxybutyrate-co-4-hydroxyvalerate], and the like; starch-based polymers; polylactic acid and copolyesters; polyglycolic acid and copolymers; aliphatic-aromatic polyesters, such as poly(c-caprolactone), polyethylene terephthalate, polybutylene terephthalate, and the like; polyvinylpyrrolidone; polysaccharides; polyvinylimidazole; polymethacrylic acid; polyvinylamine; polyvinylpyridine; and proteins, such as gelatin, wheat and maize gluten, cottonseed flour, whey proteins, myofibrillar proteins, casins, and the like. Polymers or co-polymers of amides, for example, may include polyacrylamides.

Removable sealing agents, such as, for example, degradable and/or dissolvable materials, may be used in the sealing agent at high concentrations (such as from about 10 lbs/1000 gal to about 1000 lbs/1000 gal, or from about 30 lbs/1000 gal to about 750 lbs/1000 gal) in order to form temporary plugs or bridges. The removable material may also be used at concentrations at least 4.8 g/L (40 lbs/1,000 gal), at least 6 g/L (50 lbs/1,000 gal), or at least 7.2 g/L (60 lbs/1,000 gal). The maximum concentrations of these materials that can be used may depend on the surface addition and blending equipment available. [[convert to SI/metric]]

Suitable removable sealing agents also include dissolvable materials and meltable materials (both of which may also be capable of degradation). A meltable material is a material that will transition from a solid phase to a liquid phase upon exposure to an adequate stimulus, which is generally temperature. A dissolvable material (as opposed to a degradable material, which, for example, may be a material that can (under some conditions) be broken in smaller parts by a chemical process that results in the cleavage of chemical bonds, such as hydrolysis) is a material that will transition from a solid phase to a liquid phase upon exposure to an appropriate solvent or solvent system (that is, it is soluble in one or more solvents). The solvent may be the carrier fluid used for fracturing the well, or the produced fluid (hydrocarbons) or another fluid used during the treatment of the well. In some embodiments, dissolution and degradation processes may both be involved in the removal of the sealing agent.

Such removable sealing agents, for example dissolvable, meltable and/or degradable materials, may be in any shape: for example, powder, particulates, beads, chips, fibers, or a combination of shapes. When such material is in the shape of fibers, the fibers may have a length of about 2 to about 25 mm, such as from about 3 mm to about 20 mm. The fibers may have any suitable denier value, such as a denier of about 0.1 to about 20, or about 0.15 to about 6.

Examples of suitable removable fiber materials include polylactic acid (PLA) and polyglycolide (PGA) fibers, glass fibers, polyethylene terephthalate (PET) fibers, and the like.

In uncased wells, the zonal sealing of a specified open zone may generally be achieved by reducing the permeability of the formation rock by injecting viscous fluids into the specified zones. In one or more embodiments, the viscous fluids injected may comprise at least one of viscoelastic surfactant fluids, cross-linked polymer solutions, slick-water, foams, emulsions, dispersions of acid soluble particulate carbonates, dispersions of oil soluble resins, or any other viscosified fluid that may be subsequently dissolved or otherwise removed (such as by breaking of the viscosification).

For cased wells, zonal sealing of open zone(s) may be achieved by placing a solid removable sealing agent in the perforations or in the space between the formation rock and the casing. In one or more embodiments, the solid removable sealing agent may be a dissolvable material for zonal sealing, which may comprise acid soluble cement, calcium and/or magnesium carbonate, polyesters including esters of lactic hydroxycarbonic acids and copolymers thereof, active metals such as magnesium, aluminum, zinc, and their alloys, hydrocarbons with greater than 30 carbon atoms including, for example, paraffins and waxes, and carboxylic acids such as benzoic acid and its derivatives. Further, in one or more embodiments, the dissolvable solid removable sealing agent may be slightly soluble in a wellbore fluid at certain conditions and would have a long dissolution time in said fluid. Examples of combinations of removable sealing agents and wellbore fluids that result in slightly soluble dissolvable removable sealing agents are benzoic acid with a water-based wellbore fluid and rock salt with a brine in the wellbore fluid.

The solid removable sealing agent used for zonal sealing may be in any size and form: grains, powder, spheres, balls, beads, fibers, or other forms known in the art. In order to facilitate the delivery of the solid composition to the desired zone for sealing, the solid composition may be suspended in liquids such as gelled water, viscoelastic surfactant fluids, cross-linked fluids, slick-water, foams, emulsions, brines, water, and sea-water.

In one or more embodiments, the removable sealing agent may be a manufactured shape, at a loading sufficiently high to be intercepted in the proximity of the wellbore. The loading may be more than about 50 lb/1000 gal. The manufactured shape of the removable sealing agent may be round particles having dimensions that are optimized for sealing. Also, the particles may be of different shapes, such as cubes, tetrahedrons, octahedrons, plate-like shapes (flakes), oval, and the like. The removable sealing agent may be of any dimension that is suitable for sealing. For example, as described in U.S. Patent Application Publication No. 2012/0285692, the disclosure of which is incorporated by reference herein in its entirety, the removable sealing agent may including particles having an average particle size of from about 3 mm to about 2 cm. Additionally, the removable sealing agent may additionally include a second amount of particles having an average particle size from about 1.6 to about 20 times smaller than the first average particle size. Also, the removable sealing agent may include flakes having an average particle size up to 10 times smaller than the first average particle size.

In some embodiments, the removable sealing agent is a diverter pill. The diverter pill may be a diversion blend with fibers and degradable particles with a particular particle size distribution. The diverter pill may include about 2 to 100 bbl of a carrier fluid. The diverter pill may include a diversion blend that is used as a plug and may have a mass of 10 to 400 lbs. The diversion blend may include about 20 pounds to 200 lbs of fiber per 1000 gallons of blend. It may include about 20 to about 200 pounds of particles per 1000 gallons of blend. The diverter may include beads with an average size such as described in TABLE 1 of U.S. Patent Application Publication No. 2012/0285692 A1, which is hereby incorporated by reference in its entirety. Additionally, any other diverters that are used in the industry may qualify as removable sealing agents.

The delivery and placement of the removable sealing agent (including viscous fluids and solid compositions) for zonal sealing may be performed by bullheading the material downhole, spotting the material at the wellbore with a CT-line or slick-line, or by using downhole containers capable of releasing the material at a desired zone. In one or more embodiments, after spotting the removable sealing agent composition in the wellbore the removable sealing agent is injected into the zone to be sealed by increasing the pressure in the wellbore. Any excess of the removable sealing agent applied downhole may be removed from the wellbore by cleaning it out using a coiled tubing or washing line and an appropriate cleaner for the sealing material.

The mechanical strength of the removable seals created during the zonal sealing may be increased by compacting the removable seals with gluing systems such as epoxy resins or emulsion systems such as wax and paraffin emulsions. In one or more embodiments, the gluing systems for increasing the mechanical strength of the removable seals may be compounded with the solid removable sealing agent before placement in the wellbore or may be injected separately into the wellbore after sealing the zone with the removable sealing agent. An increase in the mechanical strength of the removable seals may also be achieved by compounding the solid removable sealing agents with at least one reinforcement agent chosen from the group including fibers, deformable particulates, and particles coated with temperature and/or chemically activated formaldehyde resins.

Further, as mentioned above, for cased holes, the workflow of the present disclosure may also include creating openings in the casing to create the one or more open zones and enable access to the formation. It is also within the scope of the present disclosure that zonal sealing may be combined with the creation of the open zone(s). For example, a sequence may include creation of open zone **1**, sealing of open zone **1**, creation of open zone **2**, sealing of open zone **2**, etc., which may be performed as many times as desired, and in combination with wellbore clean out if desired. This procedure may allow for the selective sealing of various wellbore zones with various removable sealing agents.

Once a target zone or zones has had its removable sealing agent selectively removed, treatment of the target zone may be performed. Further, as one or more other zones may still be sealed with removable sealing agents, such sealed zones may not be subjected to the treatment at the given stage, and in fact, may be inaccessible to such treatments given the removable sealing agent in place. In one or more embodiments, the at least one treatment may be a propped fracturing treatment, a non-propped fracturing treatment, a slick-water treatment, an acidizing acid fracturing, and/or an injection of chelating agents. The injecting fluid may be selected from one of water, slick-water, gelled water, brines, viscoelastic surfactants, cross-linked fluids, acids, emulsions, energized fluids, foams, and mixtures thereof.

Assuming one or more zones remain sealed (and such zones warrant treatment), after performing the at least one treatment stage, the treated zone may optionally be isolated or sealed in order to temporarily decrease or stop fluid penetration therein. This isolation or sealing may be achieved by several methods including plugging the perforations, the wellbore, or the annulus space between the casing and the borehole in the treated zone, including use of the various removable sealing agents described above. However, it is also within the scope of the present disclosure that conventional zonal isolation and diversion techniques may be used to isolate the treated zone such as pumping degradable and/or soluble ball sealers, setting sand or proppant plugs, setting packers, and bridge plugs including flow-through bridge plugs, and using completion conveyed tools such as sliding sleeves and wellbore valves. While sealing has been used to describe the sealing of the sandface, leaving the wellbore open, isolation is used to describe the complete closing off of a section or zone of the wellbore. When conventional zonal isolation and diversion techniques are utilized to effectively isolate a treated zone, the de-isolation of the treated zone may be performed by conventional techniques known in the art such as creating pressure draw across the casing to remove ball sealers from the perforation tunnels, wellbore clean out with a coiled tubing line, unsetting bridge plugs or milling them out, etc.

As mentioned above, the treated target zone may be sealed through the use of various removable sealing agents described above. For example, sealing of the treated zone may also be achieved using various particulate materials such as rock salt, oil-soluble resins, waxes, carboxylic acids, cements including acid soluble cements, ceramic beads, glass beads, and cellophane flakes. Additionally, permeability reduction in the treated target zone may be achieved by injecting viscous fluids, foams, emulsions, cross-linked fluids, viscoelastic surfactant fluids, brines, and mixtures thereof into the treated formation zone. Permeability reduction in the treated formation zone may also be achieved by injecting suspensions of solids such as carbonates, polyesters, rock salt, oil-soluble resins, waxes, carboxylic acids, and mixtures thereof.

In one or more embodiments, modification of the stress field in the treated zone may also be a way of sealing the target zone after treatment. Modifying the stress field in a treated target zone of the formation may be achieved by increasing the pore pressure in the treated target zone by injecting fluids including water, oil, foams, emulsions, cross-linked fluids, viscoelastic solid fluids, brines, and mixtures thereof. Alternatively, or in addition, the stress field may be modified by cooling or heating the formation rock in the treated target zone by using downhole heaters or coolers, or injecting heated or cooled fluids including energized fluids and gases in the treated zone of the formation.

As the operation progresses beyond the initially treated target zone(s), at least one of the sealed open zones may be selectively unsealed. That is, one or more wellbore zones sealed may be selectively unsealed to facilitate their treatment during the multi-stage treatment process. For embodiments using a solid, dissolvable component as the removable sealing agent, the selective unsealing of at least one sealed wellbore zone may be accomplished by contacting the removable sealing agent comprising the solid, dissolvable component with a suitable dissolving agent to dissolve the dissolvable component. In one or more embodiments, suitable dissolving agents may comprise at least one of inorganic acids (such as hydrochloric acid), organic acids (such as formic acid, acetic acid), hydroxides, ammonia, organic solvents, diesel, oil, water, brines, solutions of organic and/or non-organic salts, and mixtures thereof. For example, the dissolvable components calcium carbonate, boric acid, and paraffin are selectively dissolvable by 10% HCl, 10% NaOH, and hexane, respectively, while remaining substantially insoluble when contacted by other dissolving agents. In one or more other embodiments in which viscous fluids are used as the sealing material, the viscous fluids may be broken by breaker fluids known to reduce the viscosity thereof. For example, viscoelastic surfactants containing a quaternary amine group may possess a pH-dependent viscosity profile such that the fluid viscosifies at certain pH values, and may have a reduced viscosity at a lower pH value.

The delivery and placement of the dissolving agent or breaker for the selective removal of the removable sealing agent may be performed by bullheading the dissolving agent or breaker downhole, spotting the dissolving agent or breaker at the wellbore with tubing or a coiled tubing string (including any tubing with an inner diameter less than 1 inch), or by using downhole containers capable of releasing the dissolving agent or breaker at the sealed zone to dissolve or otherwise break the removable sealing agent. When using a fluid flush to deliver the dissolving agent or breaker to a sealed zone, it may be desirable to minimize contact of the fluid including the dissolving agent or breaker with sealed zones that are not intended to have the removable sealing agent removed and be unsealed, while maximizing the contact of the fluid including the dissolving agent or breaker with the sealed target zone or zones that are intended to have the removable sealing agent removed and be unsealed.

As mentioned above, in one or more embodiments, the aforementioned stages of treating the target zone, optional isolation or re-sealing of the treated target zone at stage, and/or selectively removing the removable sealing agent from a different untreated target zone may be repeated as many times as desired for the multi-stage treating of the specified wellbore interval. The decision about each stage and treatment continuation may be made on the multi-stage treatment job design and/or on data obtained during the multi-stage treatment process.

Specifically, in one or more embodiments, a cased wellbore open zone sealing may utilize a sequence, performed at least one time, comprising creating an open zone in the casing and sealing the created open zone with a removable sealing agent. Utilizing this sequence may allow for the sealing of the created wellbore zones with solid removable sealing agents comprising different dissolvable components. For example, the three solid dissolvable components may be used in a system for sealing at least three different zones, each with a different solid removable sealing agent. Thus, in one or more embodiments, a zonal sealing method may utilize a sequence of creating and/or sealing a first open zone with a solid removable sealing agent comprising a first dissolvable component, creating and/or sealing a second open zone with a solid removable sealing agent comprising a second dissolvable component, and repeating the sealing process with different dissolvable components as many times as desired for the chosen treatment process. In particular embodiments, the steps of using a dissolving agent to selectively unseal a previously sealed zone to create an opened target zone and performing a treatment on the created open target zone may be substituted anywhere in the sequence recited above.

Eventually, after the desired zones have been treated, communication between sealed or isolated zones and the wellbore may be reestablished so that the job can be completed and the wellbore can be put into production. The sealed and isolated zones of the wellbore may be unsealed and de-isolated using the techniques described above. Specifically, de-isolation techniques may include, for example, creation of pressure draw across a casing to remove ball sealers from perforation tunnels, wellbore clean-out with coiled tubing, unsetting bridge plugs and milling them out, etc.

In some embodiments, the multi-stage treatment method outlined above may be applied to wellbores that have zones that have previously undergone stimulation treatments. In this way, the wellbore may undergo re-stimulation treatments of the previously treated zones or the removable sealing agents may serve to seal the previously treated zones while untreated zones undergo stimulation treatments via a multi-stage treatment method. Types of treatments that zones of a wellbore may have undergone or that may be repeated (re-stimulation) during embodiments of a multi-stage treatment method described herein generally include fracturing operations, high-rate matrix treatments and acid fracturing, matrix acidizing, and injection of chelating agents.

In one or more embodiments, in a wellbore that has at least one zone that has previously undergone stimulation treatments there may exist at least one open zone. The at least one open zone may be one of the zones of the wellbore that has previously undergone stimulation treatments or the open zone may not have previously undergone stimulation treatments. Additionally, there may be a combination of open zones that have been treated along with zones that have not previously undergone stimulation treatments. Subsequently, at least one open zone of the wellbore may be sealed with one or more removable sealing agents, while leaving at least one open zone unsealed. The at least one open zone may then be treated while the at least on other zone is sealed. Following the treatment, access may be enabled to at least one zone. In some embodiments, enabling access to at least one zone may include selectively removing at least one removable sealing agent from a zone that was previously sealed. In some embodiments, enabling access may include creating an open zone by perforating the wellbore casing with perforating charges, jetting with a coiled tubing (CT) line or slick-line conveyed tools, cutting the casing, manipulating at least one sliding sleeve or wellbore casing valve within the wellbore or any other known methods for creating an open zone in a well. In some embodiments, manipulating at least one sliding sleeve or wellbore casing valve within the wellbore or the creation of an open zone within a wellbore may enable access to an untreated zone of the formation.

Further, it is also within the scope of the present disclosure that creation of openings in a casing may involve controlled dissolution of a sealing material that is in a plugged or sealed zone. In such a case, the removable sealing agent may be slightly soluble in a wellbore fluid at certain conditions and would have a long dissolution time in said fluid. Upon extended exposure to such wellbore fluid, the removable sealing agent may dissolve and reveal openings. Examples of combinations of removable sealing agents providing slightly soluble dissolvable components are benzoic acid with a water-based wellbore fluid as the dissolving agent and rock salt with brine in the wellbore fluid as the dissolving agent.

After treatment of the interval **28** is completed in accordance with the embodiments of FIG. **11**D, in some embodiments the isolation object **18** may be removed from the target depth **12** and retrieved via the cable **32**, or by other retrieval systems or methods as previously mentioned, e.g., a separate wireline, coiled tubing, tractor, self-propulsion, pump-out, flotation, etc. In some other embodiments, the cable **32** may be disengaged from the isolation object **18** and retrieved separately, e.g., by initiating an electrical, mechanical or chemical weak point to break the link with the isolation object **18**. In these embodiments the isolation object **18** may be abandoned downhole, retrieved separately, and/or where it is degradable, removed from the target depth by initiating the appropriate degradation and/or removal protocol.

After treatment of the interval **28** is completed in accordance with the embodiments of FIGS. **11**A-**11**D, or completed to the extent the particular treatment is facilitated or desired by maintaining the isolation effected by the isolation object **18** below the interval **28**, in some embodiments the procedure of FIGS. **11**A-**11**D can be repeated iteratively one or more additional times in a different interval associated with a different target depth, e.g., one or more successively higher target depths and intervals. In some embodiments, where the isolation object **18** is movable, for example, the object **18** may be successively disengaged from isolation at the target depth **12**, relocated above the treated interval **28**, and re-set above the interval **28** and below the next interval in the series to be treated, and so on. If desired, other intervals (not shown) above the isolation object **18** may be treated concurrently and/or serially, e.g., by optionally relocating and setting the object **18** above the previously treated zones, removing any associated plugs or diverters, and/or introducing a treatment fluid into the fracture zone(s) of the successively higher intervals. In other embodiments, successively lower intervals/target depths may be serially treated for "heel-to-toe" treatment in a similar manner, e.g., to total depth.

With reference to FIGS. **12**A-**12**D, well configurations according to some embodiments of another representative operational sequence are schematically illustrated, wherein like reference numerals correspond to like parts with respect to FIGS. **11**A-**11**D. In FIG. **12**A, the well **10** is shown with predetermined target depths **12**, **13** at which the respective retaining subs **14**, **15** have been installed with the casing **16** during placement thereof. The perforating gun **20** is shown en route to the interval **28**.

Also shown in FIG. **12**A is an initiation sub **100** that has been installed at the toe or total depth of the well **10**, and has been utilized to treat a first stage and form the corresponding first fracture zone **102**, which may be used for pump down operations in some embodiments. In embodiments, the initiation sub **100** comprises an initiator rupture disk valve (RDV) **105** that can eliminate an intervention trip into the well **10** that would otherwise be required by the method described, for example, in U.S. Pat. No. 6,543,538. The RDV **105** in some embodiments allows for the first fracture zone **102** to be initiated easily and without intervention. The RDV **105** in some embodiments contains two rupture discs that block the flow and pressure from the well **10** to the inside of the tool **100**. Once the RDV **105** is pressured up and activated according to some embodiments, pumping of the first fracturing zone **102** can be performed at the desired rate and proppant concentration through helical slots in the sub **100** without the need for perforation with a perforating device.

The initiator valve **100** in these embodiments may be activated by increasing bottom-hole pressure slightly above the casing test pressure, which causes one or both of the rupture disks to fail and a sleeve in the valve **100** to open, exposing any cement sheath and the formation to the wellbore fluid; and the first zone **102** can be fractured via the RDV before pump-down plug-and-perf operations begin. Injectivity of the well **10** can be established in some embodiments by fracturing via the initiation sub **100**, so that some or all of the subsequent placement of tools and/or treatment fluids can be done by pumping with a motive fluid that can egress from the well **10** via the fracture zone **102**.

Suitable rupture disk valves, such as the rupture disk valve **105**, are described for example in SPE 162658.

With reference to FIG. **12**B, in the next operational sequence according to some embodiments, the perforating gun **20** is deployed in the well **10** to perforate a plurality of perforation zones **22**, **24**, **26**, **27** in the interval **28** by pumping the gun **20** to depth and shooting clusters in the target interval **28** via wireline **30**.

With reference to FIG. **12**C, in the next operational sequence according to some embodiments, the dissolvable isolating object **18** is shown tethered to the distributed measurement cable **32** and deployed to seat in the retaining sub **14**, in a manner similar to FIG. **11**C.

With reference to FIG. **12**D, in the next operational sequence according to some embodiments, the isolation object **18** is tightly set to isolate the interval **28** from the lower section of the well **10** containing the first fracture zone **102**, and the interval **28** is treated by injecting a fracturing treatment fluid via the perforation zones **22**, **24**, **26**, **27** (see FIG. **2**C) while monitoring treatment progress via the cable **32** to form respective fracture zones **36**, **38**, **40**, **41**, in a manner similar to FIG. **11**D. In some embodiments, following the treatment of zone **28**, a weak point is activated and the cable **32** is pulled out of the hole, in preparation for repeating the operational sequence for treating a zone above the next higher retention sub **15**.

Although only a few example embodiments have been described in detail above, those skilled in the art will readily appreciate that many modifications are possible in the example embodiments without materially departing from this invention. For example, any embodiments specifically described may be used in any combination or permutation with any other specific embodiments described herein.

Accordingly, all such modifications are intended to be included within the scope of this disclosure as defined in the following claims. In the claims, means-plus-function clauses are intended to cover the structures described herein as performing the recited function and not only structural equivalents, but also equivalent structures. Thus, although a nail and a screw may not be structural equivalents in that a nail employs a cylindrical surface to secure wooden parts together, whereas a screw employs a helical surface, in the environment of fastening wooden parts, a nail and a screw may be equivalent structures. It is the express intention of the applicant not to invoke 35 U.S.C. § 112, paragraph 6 for any limitations of any of the claims herein, except for those in which the claim expressly uses the words 'means for' together with an associated function.

What is claimed is:

1. A method for multi-stage well treatment, comprising:

(a) perforating a first interval in the well above a first target depth;

(b) deploying to the first target depth an isolation object tethered to a distributed measurement cable from the surface, the distributed measurement cable having a polymeric outer jacket disposed about at least one inner polymeric jacket, wherein the measurement cable has a core disposed within the at least one inner polymeric jacket, the core being at least one optical fiber conductor;

(c) isolating the well at the first target depth with the isolation object by directly seating the isolation object against an inner diameter restriction of a retention sub installed at the first target depth;

(d) treating the first perforated interval in a plurality of stages; and

(e) concurrently with (d), receiving measurements from the distributed measurement cable for monitoring each stage of the treatment;

wherein the perforation (a), the deployment (b), the isolation (c), and the treatment (d) concurrently with the monitoring (e) are performed in the recited order.

2. The method of claim **1**, further comprising detaching the distributed measurement cable from the isolation object, and removing the distributed measurement cable from the well.

3. The method of claim **1**, further comprising leaving the distributed measurement cable in the well, initiating production from the first treated interval and concurrently obtaining measurements from the distributed measurement cable to monitor the production.

4. The method of claim **1**, further comprising repeating the perforation (a), deployment (b), isolation (c), treatment (d), and monitoring (e), one or more times with respect to successive intervals above successively higher target depths.

5. The method of claim **1**, further comprising treating a stage below the first target depth prior to treatment of the first interval.

6. The method of claim **5**, wherein the stage below the first target depth is treated prior to perforating the first interval.

7. The method of claim **5**, wherein treating the stage below the first target depth comprises actuating a rupture disk valve.

8. The method of claim **5**, wherein treating the stage below the first target depth comprises deploying one or more perforating guns below the first target depth to initiate fluid entry into the stage below the first target depth.

9. The method of claim **1**, further comprising installing the retention sub with a casing string at the first target depth.

10. The method of claim **1**, wherein the isolation object comprises a degradable ball.

11. The method of claim **1**, wherein the measurements received are selected from fluid flow rate, distributed temperature, distributed vibration, distributed pressure, and combinations thereof.

12. The method of claim **1**, wherein the treatment (d) comprises fracturing.

13. The method of claim **12**, wherein the fracturing comprises pumping a treatment fluid comprising proppant laden stages separated by one or more diverter pills.

14. The method of claim **13**, further comprising adjusting in (d) one or more of respective sizes of the proppant laden stages, number of the diverter pills, and volumes of the diverter pills, in response to the measurements received in (e).

15. A method for multi-stage well treatment, comprising:

(a) installing in a casing string an initiation sub adjacent a toe of the well, wherein the initiation sub comprises a rupture disk valve;

(b) installing in the casing string a plurality of retention subs at a first target depth and one or more successively higher target depths above the initiation sub;

(c) actuating the initiation sub to treat a stage adjacent the initiation sub, wherein actuating the initiation sub comprises bursting the rupture disk valve;

(d) perforating a first interval in the well above the first target depth;

(e) deploying to the first target depth an isolation object tethered to a distributed measurement cable from the surface, the distributed measurement cable having a polymeric outer jacket disposed about at least one inner polymeric jacket, wherein the measurement cable has a core disposed within the at least one inner polymeric jacket, the core being at least one optical fiber conductor;

(f) directly seating the isolation object deployed in (e) against an inner diameter restriction of the retention sub installed at the first target depth to isolate the well at the first target depth;

(g) treating the first perforated interval in a plurality of stages;

(h) concurrently receiving measurements from the distributed measurement cable for monitoring each stage of the treatment in (g);

(i) detaching the distributed measurement cable from the isolation object seated in (f); and

(j) repeating at least the perforation in (d), the deployment in (e), the seating in (f), the treatment in (g), and the monitoring in (h), one or more times with respect to successively higher intervals above the respective one or more successively higher target depths.

16. The method of claim **15**, further comprising:

(k) concurrently conveying landing seat installation tools to the respective retention subs, and perforating tools to the respective intervals, with a wireline; and

(l) installing landing seats with the respective landing seat installation tools in the respective retention sub to receive the respective isolation objects.

17. The method of claim **15**, further comprising removing the isolation object.

18. The method of claim **15**, wherein the measurements received are selected from fluid flow rate, distributed temperature, distributed vibration, distributed pressure, and combinations thereof.

19. The method of claim **15**, wherein the treatments in (c) and (g) comprise fracturing treatments.

20. The method of claim **19**, wherein the fracturing treatments in (g) comprise pumping a treatment fluid comprising proppant laden stages separated by one or more diverter pills.

21. The method of claim **20**, further comprising adjustment during the fracturing treatments in (g) one or more of respective sizes of the proppant laden stages, number of the diverter pills, and volumes of the diverter pills, in response to the measurements received in (h).

22. The method of claim **19**, wherein the fracturing treatments in (g) comprise sealing at least one open zone of the respective interval with at least one removable sealing agent, selectively removing the removable sealing agent from at least one target zone, and fracturing the at least one target zone.

23. The method of claim **22**, wherein the fracturing treatments in (g) occur while at least one open zone of the well is sealed with at least one removable sealing agent.

24. The method of claim **22**, wherein the removable sealing agent comprises manufactured shapes selected from at least one of particulates, fibers, flakes, rods, pellets and combinations thereof.

25. The method of claim **19**, wherein the fracturing treatments in the respective intervals in (g) comprise:

sealing, with a removable sealing agent, all but one of a plurality of open zones in the respective interval;

fracturing the open zone while the other zones in the respective interval are isolated or sealed or a combination thereof;

sealing the fractured zone or isolating the section of the respective interval comprising the fractured zone;

selectively removing the removable sealing agent from an untreated sealed zone; and

repeating the sequence of fracturing the open zone while the other zones are isolated or sealed, isolating or sealing the fractured zone, and selectively removing the removable sealing agent from a sealed un-fractured zone until the desired number of zones are fractured.

26. A system for multi-stage well treatment, comprising:

(a) a perforating system to convey a perforating device to perforate an interval in the well above a target depth;

(b) a deployment system to deploy an isolation object tethered to a distributed measurement cable from the surface to the target depth and isolate the well at the first target depth with the isolation object by directly seating the isolation object against an inner diameter restriction of a retention sub installed at the target depth, the distributed measurement cable having a polymeric outer jacket disposed about at least one inner polymeric jacket, wherein the measurement cable has a core disposed within the at least one inner polymeric jacket, the core being at least one optical fiber conductor;

(c) a treatment system to treat the perforated interval with a treatment fluid in a plurality of stages; and

(d) a distributed measurement collection system to receive and interpret measurements from the distributed measurement cable during the treatment to monitor the plurality of the treatment stages.

27. The system of claim **26**, further comprising a weak point activatable to detach the distributed measurement cable from the isolation object for removal of the distributed measurement cable from the well.

28. The system of claim **26**, wherein the perforating, deployment, treatment and distributed measurement collection systems are operable to repeat the perforation, deployment, treatment, and measurement interpretation with respect to one or more successively higher target depths and respective intervals.

29. The system of claim **26**, wherein the optical fiber conductor comprises:

a pair of half-shell conductors;

an insulated optical fiber located between the pair of half-shell conductors, wherein the insulated optical fiber is coupled with the pair of half-shell conductors; and

an optical fiber conductor jacket disposed about the pair of half-shell conductors.

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